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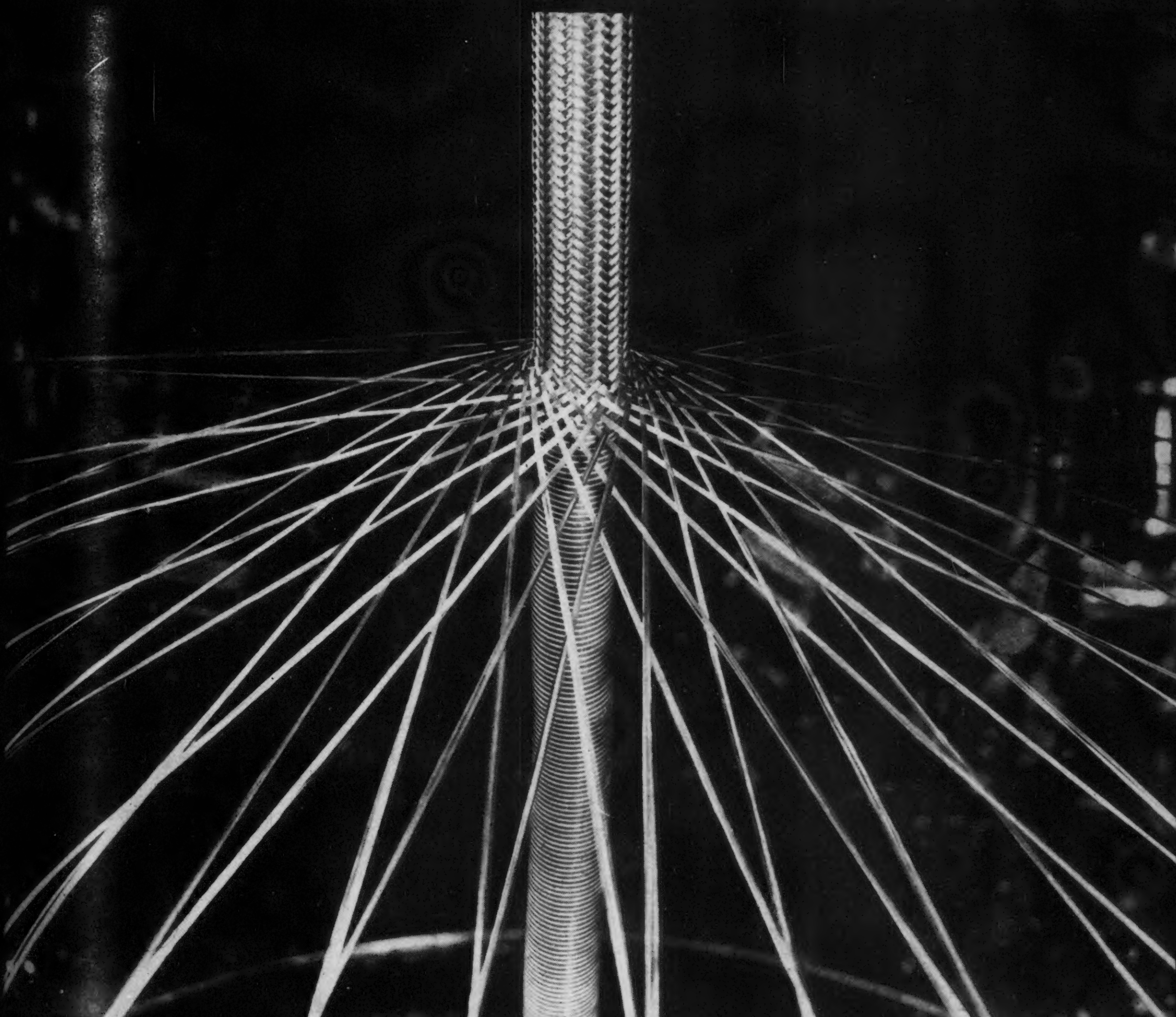

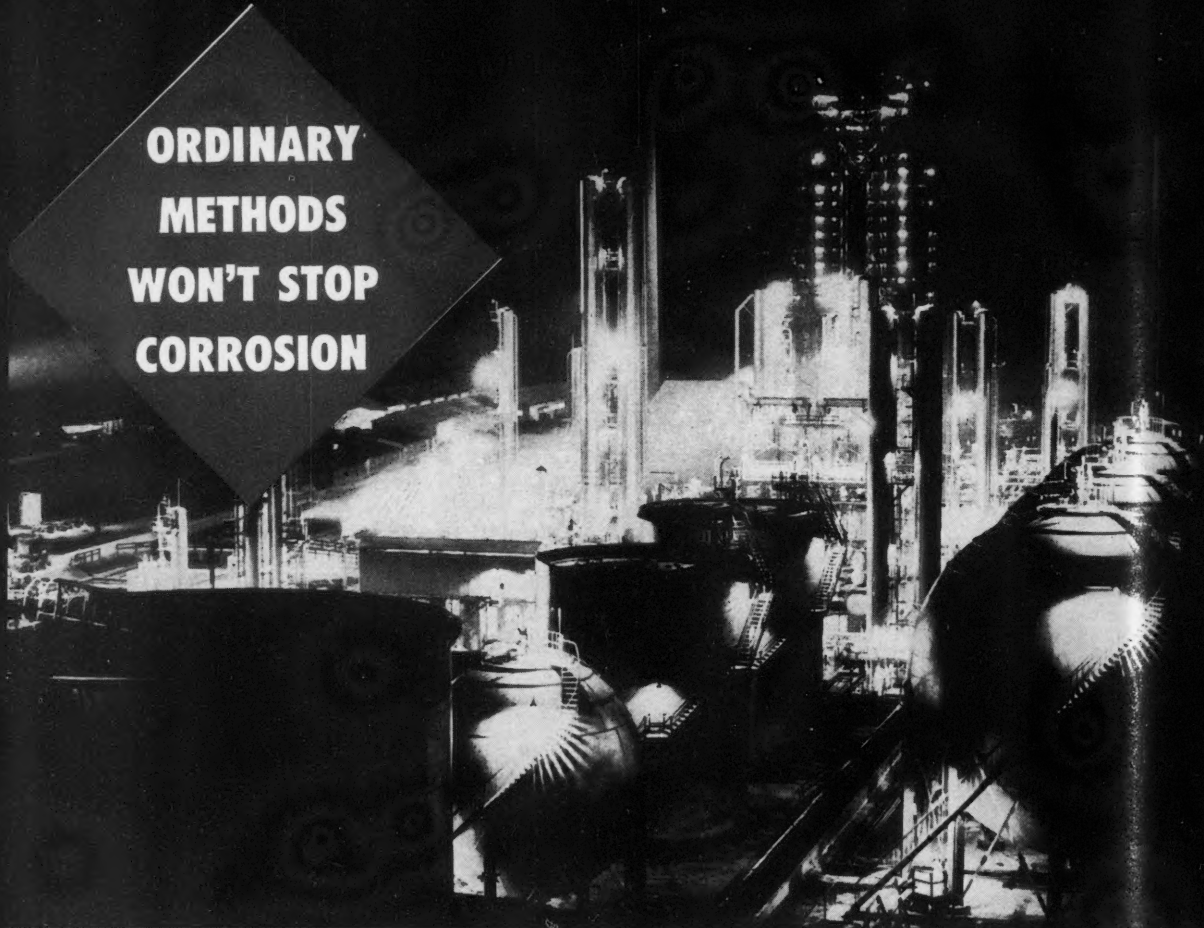

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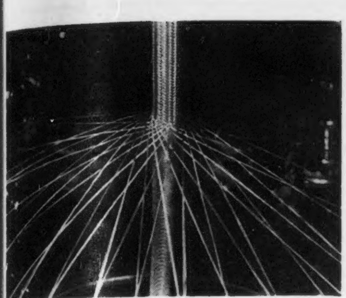

THIS MONTH'S COVER—Round wire or flat ribbon braid in silicon bronze, nickel, Type 321 stainless steel or copper-clad steel can be laid either 2-over-2 or 1-over-1 in this operation shown at Titeflex, Inc., Newark, N. J. Braid is laid directly over flexible inner cores of brass, 356 alloy bronze, 48% nickel alloy steel and Monel.

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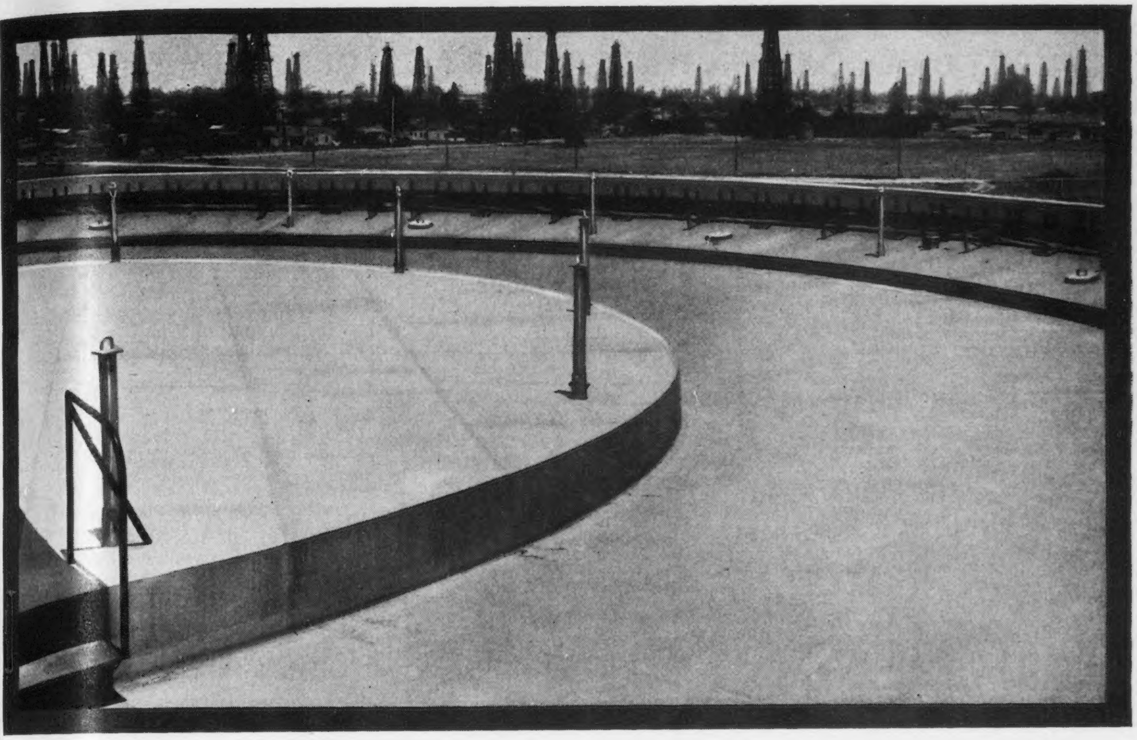

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—after more than 3 years rough service

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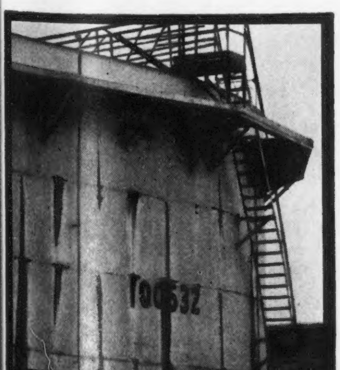

photo shows a tank side finished at the same time with ordinary paint. Direct sun isn't so great a factor. Yet, paint failure and rust stains are very evident. However, note the top rim, fiinished with a coating based on VINYLITE Resins, is in excellent condition.

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Photos courtesy Plastic Coating Corporation, Houston, Texas.

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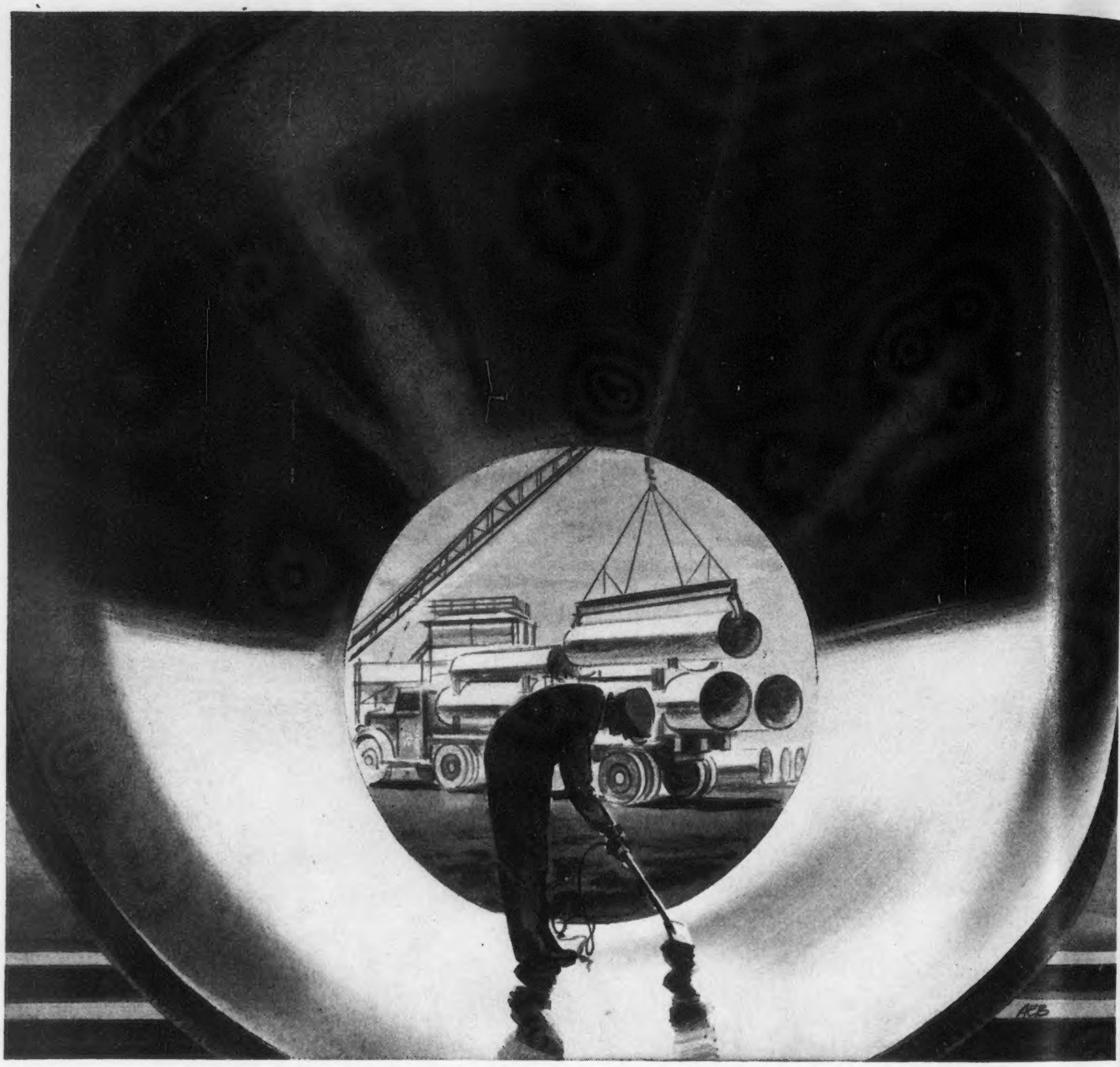

THE NATIONAL ASSOCIATION OF CORROSION ENGINEERS

is a non-profit, scientific and research association of individuals and companies concerned with corrosion or interested in it, whose objects are:

(a) To promote the prevention of corrosion, thereby curtailing economic waste and conserving natural resources.

(b) To provide forums and media through which experiences with corrosion and its prevention may be reported, discussed and published for the common good.

(c) To encourage special study and research to determine the fundamental causes of corrosion, and to develop new or improved techniques for its prevention.

(d) To correlate study and research on corrosion problems among technical associations to reduce duplication and increase efficiency.

(e) To promote standardization of terminology, techniques, equipment and design in corrosion control.

(f) To contribute to industrial and public safety by promoting the prevention of corrosion as a cause of accidents.

(g) To foster cooperation between individual operators of metallic plant and structures in the joint solution of common corrosion problems.

(h) To invite a wide diversity of membership, thereby insuring reciprocal benefits between industries and governmental groups as well as between individuals and corporations.

It is an incorporated association without capital stock, chartered under the laws of Texas. Its affairs are governed by a Board of Directors, elected by the general membership. Officers and elected directors are nominated by a nominating committee in accordance with the articles of organization. Election is by the membership.

Inquiries regarding membership, and all general correspondence should be directed to the Executive Secretary at the administrative headquarters of the National Association of Corrosion Engineers at 1061 M & M Building, No. 1 Main Street, Houston 2, Texas.

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Directors

Corrosion

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An Association of Individuals and Organizations Concerned with Control of Corrosion

1061 M & M Building — Houston 2, Texas

Vol. 9 — September, 1953 — No. 9

Organization and Activities of

Technical Practices Subcommittee 15A On Corrosion Control in Railroad Tank Cars

By J. ROBERT SPRAUL,* Chairman

AT PRESENT there are approximately 141,000 tank cars transporting about 600 different commodities operating in the United States. An increasing number of these materials exhibit corrosive properties or require protection from contamination by corrosion products from the shipping container. It was felt that a subcommittee, NACE's TP-15 on Corrosion Control in the Transportation Industries could contribute to the solution of some of these problems. The initial work of assembling a committee and comparing ideas was conducted during the fall and winter of 1952-53.

The first meeting was held on March 16, 1953, during the Ninth Annual Conference of the National Association of Corrosion Engineers in Chicago. Thirteen committee members and seven guests attended the meeting at which the following committee objectives were adopted:

> The objectives of Technical Practices Sub-Committee TP-15A of the National Association of Corrosion Engineers shall be:
>
> a) To stimulate and encourage research and interest in determining the causes of and methods of controlling corrosion of railroad tank cars.
> b) To assist in the development and evaluation of testing and research methods for use in selecting construction materials and protective systems for use in railroad tank cars.
> c) To serve as a means of coordinating and disseminating technical information on problems associated with tank car use.

Three initial activities were started at the March 16, 1953, meeting:

1. Evaluation of corrosion testing procedures and correlation of these results with field experience. The purpose of this program is to provide data useful in the selection of protective coatings and construction materials for tank cars.
2. Development of recommended methods for cleaning the interior of tank cars to prevent damage to linings and construction materials.
3. Recommended practices for the preparation of tank car interiors prior to application of protective coatings.

The committee now consists of the following 22 members:

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Celanese Corporation of America

F. L. Whitney, Jr.
Monsanto Chemical Company

T. H. Caldwell
The Dow Chemical Company

L. R. Honnaker
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* General American Transportation Corp., Research & Testing Laboratory, 300 West 151st St., East Chicago, Ind.

Corrosion-Fatigue Failure of A Marine Propeller Shaft ★

By CARL A. ZAPFFE*

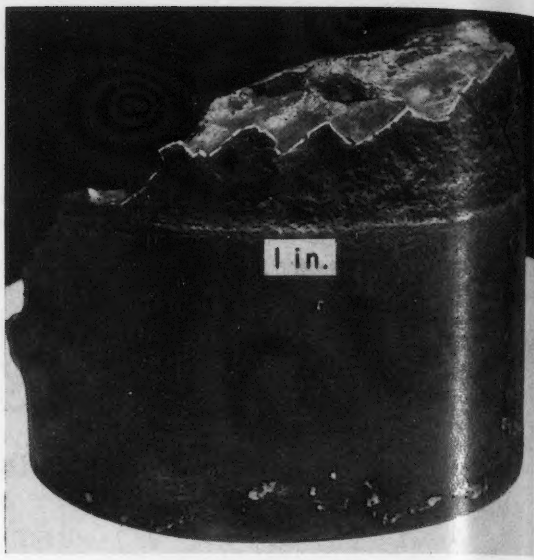

Figure 1—Outboard fragment of tail shaft at fracture. The smooth base above the saw cut originally rested within the outboard bushing, the remainder being exposed to corrosion from brackish water which leaked into the stern tube. Note the rectilinearity of the fracture profile.

Abstract

An ususually clear example of corrosion-fatigue failure is used as a basis for discussing those forms of fracture in which chemical attack combines with mechanical stress to destroy an engineering structure. The term "mechanochemical" is introduced to cover the entire category of stress-corrosion, corrosion-fatigue, metal-fusion, stress-rupture and related types of attack; and a new fracture terminology is given for precise description of fracture details. A generalized thermodynamic theory is then proposed on the basis of $\Delta F = f(T, X, P)$ where fissuring results from stress-imposed changes in thermodynamic microsystems such as (a) grain boundaries to produce intergranular separations and (b) subgrain or micellar boundaries to produce transgranular cracking.

Introduction

COMBINATIONS of mechanical stress and chemical attack have produced types of failures in metals which are not yet fully understood.[1,2,3] One of these is corrosion-fatigue, widely discussed since Haigh[4] described it in 1917. A particularly fine example has recently been studied during a research program on fracture mechanics.** Its principal features are here described, with reference to a new classification of fracture detail which allows a precise treatment of fracture pattern and chronology.[5]

Macrostructure

Figure 1 shows a section of an 8-inch diameter tail shaft from a marine tug of 200 gross tons. This shaft was supported at both ends by bronze bearings and sheathed by a cast-iron stern tube. Apparently faulty servicing had allowed the lubricant within the stern tube to be displaced by the brackish water of Chesapeake Bay, the resulting combination of corrosion and operating stresses leading to failure of corrosion-fatigue type. Fracture developed off the inboard end of the outboard bearing, the engineward shaft fragment causing further destruction of the stern tube before the motors were cut.

In the photograph, the base of the specimen is the sawed end from that portion resting within the outboard bearing. The surface is comparatively smooth, the shaft diameter remaining the original eight inches. A sharp boundary visible above the base of the specimen marks the inboard end of the bearing, beyond which severe corrosion occurred. The upper surface of the photograph is the fracture face.

In Figure 2, two views are shown of a longitudinal ¼-section sawed from the matching fragment engineward from the specimen in Figure 1. The fracture face is again at the top of the photograph. The corroded surface is at the right, the rough-polished deep-etched section at the left. Arrows match several outstanding cracks which can be followed from the surface on into the body of the shaft.

Two features are outstanding:

1. numerous cracks penetrate deeply into the steel, and
2. the surface pattern of cracking is a gridwork of almost perfect rectilinearity disposed at 45 degrees to the shaft axis.

This gridwork depicts the normals to the counterhelixes of maximum tensile stress typical of a bar or tube subjected to reversing axial torsion, as in the present service conditions. Figure 3 reproduces a classical drawing from a book by Hartmann,[6] published in 1896, from which the term "Hartmann's lines" originates. It will be seen that Hartmann's stress pattern is exactly the pattern of fracture initiation which shows in plan in Figure 2 and in profile in Figure 1.

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* Metallurgist, Laboratory of Carl A. Zapffe and Associates, Baltimore, Md.
** Sponsored in part by the Office of Naval Research, Contract 6-ONR-258.

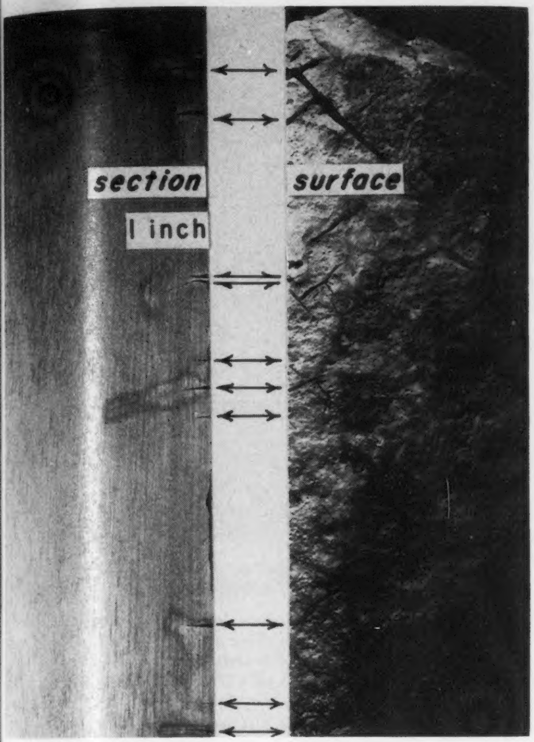

Figure 2—Matched views of longitudinal ¼-section of inboard fragment. The corroded surface on the right shows fissures at typical positions normal to the counterhelixes of maximum tension. The rough-polished and deep-etched face on the left discloses the deep penetration of some of these fissures. This specimen is the matching fracture of Figure 1.

Microstructure

Two photomicrographs in Figure 4 provide some detail from a typical crack. Occasionally a granular individual can be found separated by corrosion along or near its boundary; and toward the tip of the crack a silicate inclusion has apparently favored dissolution. Nevertheless, the progress of corrosion has clearly been a primary function of stress maxima, the microstructure providing only minor secondary effects. This confirms the failure as being typically corrosion-fatigue in type.

Macrofractography

In Figure 5, a macrofractograph of the specimen in the previous Figure 1 records the story of the failure. A toothy rim surrounds the specimen as a concentric shell of steel deteriorated by mechanochemical attack. One critical crack, its sidewall exposed in plan at "*a*," had penetrated to that depth sufficient for continued mechanical propagation of dehesion unaided by corrosion—this culminating in fracture.

Since the detailed history of the failure is recorded in the fractographic pattern, several technical terms will be defined for purposes of precise description.

First, all traces and markings to be found on fracture surfaces in general are divided between two major categories:[5]

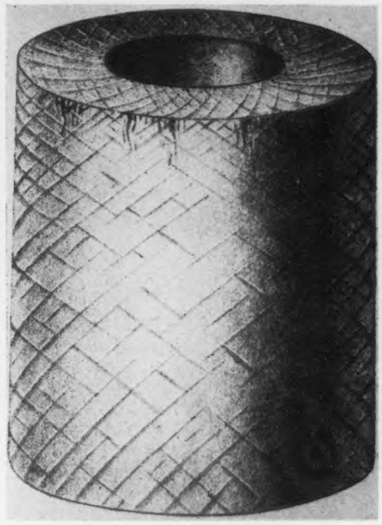

Figure 3—Strain figures on the surface of a tube deformed by torsion. A reproduction from Hartman's book[6] of 1896.

Type I —*Endogenous* features expressing structures of the solid

Type II—*Exogenous* features expressing structures of the rupturing stress

Because the pattern of Figure 5 is entirely a product of external or exogenous factors, mechanical and chemical, further consideration need not be given Type I. The details of Type II patterns are subdivided among a triad of terms:

II-a. *Focal,* having to do with the origin of the fracture;

II-b. *Peripheral,* expressing the outer boundary of the fracture in progressive stages of its development;

II-c. *Conjunctural,* resulting from the meeting of separate fracture elements.

In Figure 5, superimposed letters designate these principal forms of fracture detail. At "*a*" the *focus* of the fracture is the corroded surface of that particular mechanochemical crack which eventuated in the failure. Immediately neighboring upon this focal area are *peripheral* markings, outstanding examples being indicated by the "*b*" arrow. These peripheral markings are usually closely perpendicular to the direction of fracture; and in symmetrical fracture traverses they approximate concentric rings about the focus. Their form derives from undulations in fracture traverse, which derive in turn from variations in fracture velocity. If the fracture velocity drops to zero, as in cyclic stressing and fatigue failures, the traverse becomes discontinuous rather than undulating, giving particular prominence to peripheral markings.

Accordingly, the area enclosed by a peripheral trace represents the extent and the shape of the dehering area at a particular stage of development of the fracture.

Approximately perpendicular to the peripheral traces, *conjunctural* markings often appear as indicated at "*c*." These result from the meeting of local fracture units, which often extend fingerlike ahead of the periphery, sometimes even developing as isolated areas of dehesion within the solid in advance of the fracture front. When

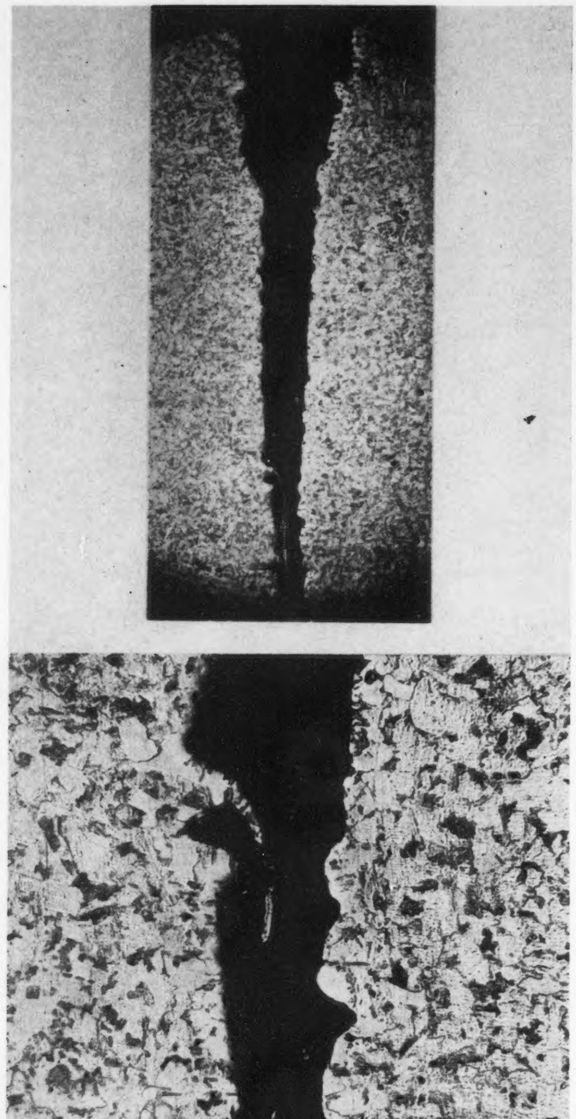

Figure 4—Photomicrographs of a typical fissure. Except for occasional preferences for a grain boundary or the area of an inclusion, the corrosion patch seems uninfluenced by any factor other than stress. (Above) 11 X. (Below) 100 X.

these conjunctures are between fracture elements issuing from a single focus, and with a more or less symmetrical traverse, they lie nearly at right angles to the peripheral markings and hence approximate the fracture direction. On the other hand, conjunctures of fracture units hav-

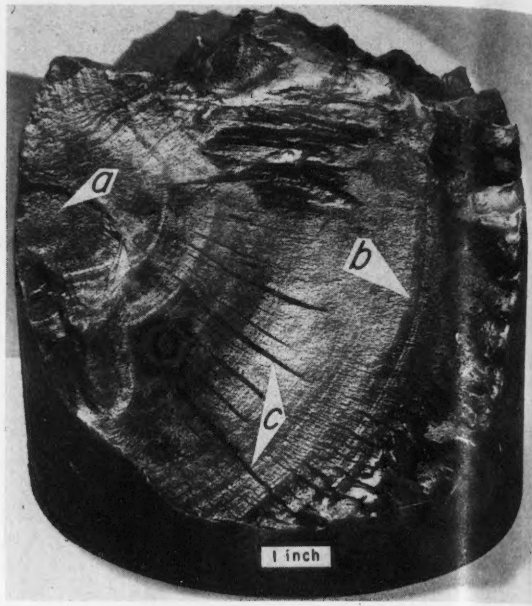

Figure 5—Macrofractograph of the outboard fragment. Details of the fracture history are revealed by the *a* focal, *b* peripheral, and *c* conjunctural markings.

ing separate foci, perhaps further complicated by irregular traverses, may have no readily interpreted relationship to fracture direction.

In the former case, the conjunctures are subclassified as *interradial;* in the latter, as *interperipheral.*[5] The markings at *"c"* in Figure 5 are interradial conjunctures and they lie closely along the fracture direction.

Mechanochemical Theory

Generalizations

Since the interaction of mechanical and chemical factors is particularly striking in the present specimen, some remarks are in order regarding fundamental concepts by which such failures can be understood. The status of theory in this field is currently one of great confusion.[1,2,3,7,8,9,10,11]* Numerous hypotheses have been offered, none wholly agreed upon except within restricted areas of study. A generalized theory remains to be outlined, uniformly underlying all those phenomena now separated for various—and sometimes variable—reasons among stress-corrosion, corrosion-fatigue and metal-fusion types, also one or more "stress-rupture" types developing under corrosive conditions at elevated temperatures.

In searching for such a theory, one generalization immediately presents itself because all associated problems have the common denominator of mechanical stress cooperating with a chemical potential to aggravate corrosive attack. The term *mechanochemical* can accordingly be proposed for inclusive reference to the entire category, regardless of the particular form of the attack. The derivation of the term is obvious and needs no further description.

Next, the single outstanding feature common to those *crack*-type phenomena here under consideration is the

* For a comprehensive discussion, which will not be undertaken here, see Harwood's recent article.[3]

selective action of corrosion which leads to fissuring of the solid. This removes the emphasis from general *mechanochemical corrosion* and places it specifically upon *mechanochemical fissuring* or cracking. It is this latter which attains an augmented importance in engineering because of its destructiveness. Nevertheless, that it remains a technological subhead of mechanochemical corrosion can be seen from thermodynamic description.

First, in order for corrosion to develop at all, a thermodynamic system must obtain in which the energy defined as free energy can be reduced through formation of reaction products. Thermodynamic formulation for the system then both

a) defines the only direction the ultimate reaction may take and
b) measures the amount of energy available to it.

As a function of —RT ln K, the change in free energy ΔF refers to the chemical potential of the reaction; and as $-nfE$, to the electrochemical potential. It is a secondary consideration whether the reaction proceeds with a flow of current or not, whereas a reduction in free energy is requisite to all reactions.

Second, since ΔF is also a function of $V\,dP$, the free-energy change of any given reaction must be altered by stress. In general, ΔF becomes more negative for conditions of negative stress, or tension, and less negative for compression. This provides a thermodynamic basis for understanding why mechanochemical fissuring always occurs in areas under tension, never in areas under compression—whether other factors of kinetic sort are active or not. Maximum negative values will occur in macropattern as a function of geometry and stress, in agreement with the observations in Figures 1, 2 and 3; in micropattern, maximum values will be integrations of numerous complex functions arising from local conditions—inhomogeneities in chemical constitution and anisotropies in internal stress—superimposed upon the macropattern. It is this micropattern which is specifically responsible for mechanochemical attack of fissure type. The thermodynamic system is here physically minute, partaking of forces of fine-capillary type and involving internal pressures of the crystal which are known to exceed the usual imposed mechanical stresses by a factor in the range of 100. Gross measurements of electrochemical potential as a function of applied stress[11] accordingly have little direct bearing upon mechanochemical fissuring. In fact, no apparatus has yet been designed which will measure the highly localized forces that are involved in transcrystalline cracking; and until that becomes possible, the matter must be left to theoretical description. Spretnak and Speiser[12] have described thermodynamic theory for free surface energy at grain boundaries and their formulations can be used to account for that augmenting of ΔF which leads to intergranular dehesion under purely chemical influences. Adding the effect of stress to the other factors affecting the surface chemistry at grain boundaries then provides a basis for understanding combined mechanochemical attack of grain-boundary type.

As for the problem of transgranular fissuring, this similarly submits to thermodynamic treatment when the grain itself is regarded as a subdivided structure. It is only necessary to postulate a maximum value for $-\Delta F$ along transgranular rather than intergranular surfaces. Read, Reed and Rosenthal[1] have already hinted at this type of explanation; the micellar theory for the solid state[13] specifically provides an answer of that form; and the consensus of solid-state physics allows for it in the current endorsement of imperfection structure, whose exact definition only remains to be agreed upon. The problem accordingly seems to evolve itself into one of capillary or surface thermodynamics in which the direct effect of stress is to alter the microsystem.

Corollaries

On the basis of these two fundamental descriptions uniting the effects of mechanics and chemistry in a single thermodynamic statement of $\Delta F = f(T, X, P)$, numerous remaining theories for mechanochemical phenomena can be accepted as corollaries. The *electrochemical theory* is essentially thermodynamic in derivation, but of fractional application. The exceptional work of Dix and Mears and their colleagues has established its validity for certain systems and strongly suggested it for many others. However, it is not acceptable as a general concept because it can have at the most a forced application, for example, to mechanochemical fissuring of nonmetallic bodies such as plastics, to fissuring of metals by other metals in liquid or gaseous form and to fissuring by noncondensing atmospheres at elevated temperatures.

Similarly, the *film-rupture theory* must be regarded as a corollary since it arises from the kinetic viewpoint, rather than the thermodynamic. That is, in order for any reaction to continue, the access of the reactants to one another must remain unobstructed. If reaction products accumulate, the free-energy characteristics at the reacting surface may be reduced toward those of an equilibrated system. Stainless steel, when placed in an oxidizing atmosphere, provides a remarkable example of a reactive macrosystem of high potential almost completely throttled by the obstruction of its own reaction product within a contained microsystem. If this product is removed by either mechanical or chemical means, the local reactive potential is restored; and this aspect of chemistry logically gives rise to a film-rupture theory for mechanochemical attack. In the passivation/activation behavior of stainless steel, this theory in its generalized form is outstanding; it very likely has first-order importance in the hydrogen-producing NaOH/Fe reaction associated with "boiler embrittlement";[9] and among the several fissuring types here under discussion, it is particularly pertinent to corrosion-fatigue. Nevertheless, the possibility of a reaction is antecedent to its culmination; and a theory based upon kinetics must remain a corollary of thermodynamic description. Removal of the reaction product is probably always helpful, and it may often be necessary, for completion of a reaction within a significant period of time; but no fundamental reason is likely to be found for making film-rupture a prerequisite of all mechanochemical fissuring.

Remaining theories, such as those concerned with internal precipitation, similarly have a restricted validity, appropriate at most for systems in which precipitation occurs. Precipitation in the solid state, of course, is intimately associated with the internal

surfaces under discussion, strongly altering the free-energy characteristics of the capillary system in particular and the chemical system in general. Preferential precipitation in the grain boundaries of austenitic stainless steel can lead to the catastrophic chemical attack known as "sensitization," even in the absence of stress; and corresponding intragranular effects of precipitation form the principal history of Izett steel.[9] Nevertheless, precipitation can scarcely afford a generalized theory, its role being influential rather than necessary.

Closure

With regard to the present specimen, the effect of stress has left a clear record in the macropattern of clockwise and counterclockwise helical fissuring, representing normals to the maximum tensile stresses developing during alternate forward and reverse propulsion of the tug. The micropattern shows the transgranular characteristics of corrosion-fatigue. Both patterns are in keeping with the outlined mechanochemical theory based upon thermodynamic considerations of $\triangle F = f(T, X, P)$, the transgranular path following maximum negative values for $\triangle F$ along internal surfaces such as postulated by the micellar theory.

Whether the initial fissuring action was importantly influenced by film-rupture behavior is regarded as a secondary consideration, also whether the reaction proceeded chemically or electrochemically. Evidence in favor of the former stands in the known mechanical effects of the cyclic stressing, and in the probable chemical effect of scale penetration by the Cl^- ion. Evidence in favor of the latter is suggested by the somewhat surprising combination of cast iron, bronze and steel found in the shaft assembly.

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Cathodic Protection of Underriver Pipe Lines★

By C. C. LOYD and JOHN R. WHITNEY

Introduction

IN 1948, approval was obtained for the installation of cathodic protection on the underriver portion of the one 12-inch and six 8-inch crude oil pipelines which lie on the bottom of the Mississippi River and connect Esso Standard Oil Company's Baton Rouge Refinery and the Anchorage Tank Farm. The economic justification for cathodic protection of these pipelines was based on a comparison of the cost of repairing leaks to the cost of cathodic protection. In 1946, an attempt was made to raise the 8-inch No. 2 line for repairs, but after several cables were broken, the attempt was abandoned for fear that some of the other lines would be damaged. The No. 2 line was a total loss and has not been used since that time. Also, in 1946, the cost of repairing a leak in the 8-inch, No. 6 pipeline was $10,611 while the total cost for cathodic protection of the seven lines was $8220.

This project was completed on May 17, 1951. The cathodic protection unit also was expected to furnish protection to the steel armor of two underriver cables, one 6.6 kv. power cable and one telephone cable, which cross the river in the protection area. Five 8-inch pipelines belonging to other industries cross the river in the protection area. These lines were bonded into the system through a variable resistor to prevent stray current corrosion. These lines are receiving some, but not complete, protection.

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Abstract

Installation of cathodic protection on the 3100-foot portion of the one 12-inch and six 8-inch crude oil pipelines under the Mississippi River which connect the Baton Rouge Refinery and the Anchorage Tank Farm was completed in May, 1951. A current density of 3.5 milliamperes per square foot was used as the minimum requirement for full protection of the 52,000 square feet of surface area of these pipelines. A 100 ampere, 30 volt rectifier and a groundbed were installed on each bank of the Mississippi River to supply the protective current to the pipelines from both sides of the river. The groundbeds were designed to utilize the mutual interference effect of the anodes to force the current to flow toward the middle of the river and to secure overlapping protection from the two units. Pipe-to-soil potential measurements on both banks of the river indicate that overlapping protection was achieved and that full protection to the pipelines has been accomplished.

Details of Design

Because of the practical difficulties involved, it was impossible to place the anode groundbeds parallel to and running the length of the pipelines to be protected. As a solution to the problem of obtaining full protection in the middle of the river, the cathodic protection unit was designed to consist of two separate rectifier units, each having its own groundbed, with one unit installed on each side of the river near the edge of the water. These installations were designed to provide overlapping protection to the pipelines at the middle of the river.

Basis

The cathodic protection unit was designed to protect approximately 21,700 linear feet of pipeline consisting of one 12-inch and six 8-inch lines having a total surface area of 52,000 square feet. A current density of 3.5 milliamperes per square foot was used as the minimum requirement for full protection; therefore, a current of 182 amperes was required to achieve full protection.

Rectifiers

Two identical, standard, selenium, oil-immersed rectifiers, rated at 30 volts, 100 amperes dc, are being used to supply the dc power required. Each rectifier is equipped with a power switch, voltmeter, ammeter and a thermal overload relay. This size rectifier was selected because it was an available standard size which would meet the current and voltage requirements, with the additional capacity to provide for necessary operating adjustments.

Transformers

The transformers being used are both 10 kva, single phase, oil-immersed units. The transformer used on the east bank of the river is rated at 2400—120/240 volts and the west bank transformer is rated at 7200—120/240 volts.

★A paper presented at a meeting of South Central Region National Association of Corrosion Engineers, New Orleans, La., October 1-3, 1952.

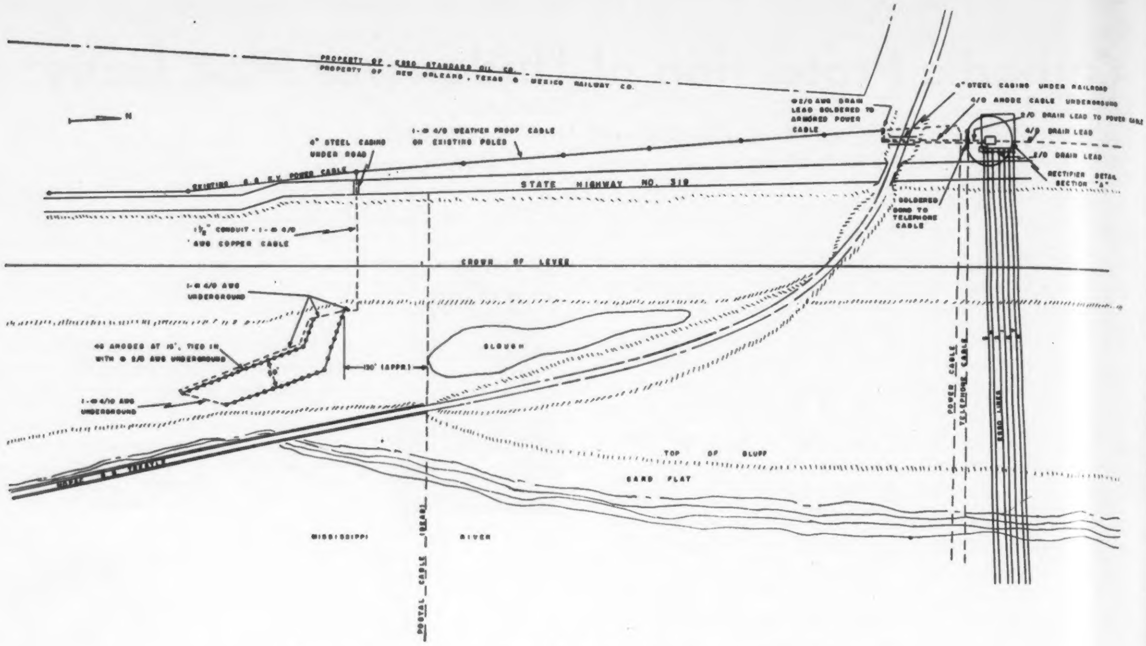

Figure 1—Cathodic protection of underriver pipe lines—west bank layout.

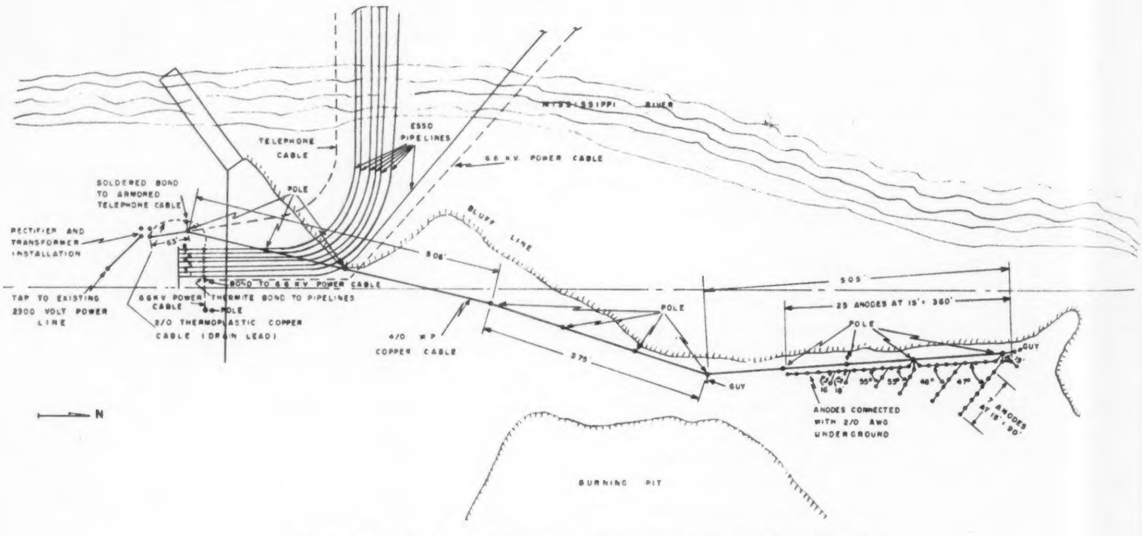

Figure 2—Cathodic protection of underriver pipe lines—east bank layout.

Anodes

Anodes used are the standard 2-inch x 80-inch cylindrical graphite anodes. They were buried vertically in holes six inches in diameter by ten feet deep and were surrounded by petroleum coke breeze backfill. The use of backfill, the cost of which is small, increases the allowable anode current fourfold, thereby reducing the number of anodes needed. The anode-to-soil resistance is also decreased by the use of backfill which resulted in lower required rectifier voltage. Backfill provides uniform resistivity for the entire surface area of the anode which produces even distribution of current leaving the anode. This eliminates premature breakdown of the anode at points of high current density and increases their life considerably. Anode life for this installation is expected to exceed twenty years.

Anode Arrangement

As shown in Figures 1 and 2 groundbeds on the east and west banks consist of 45 and 44 anodes, respectively, all spaced on 15-foot centers. Both groundbeds were placed so a portion of each is practically parallel to the lines being protected, with the rest of the groundbed placed at an angle designed to give overlapping protection at the middle of the

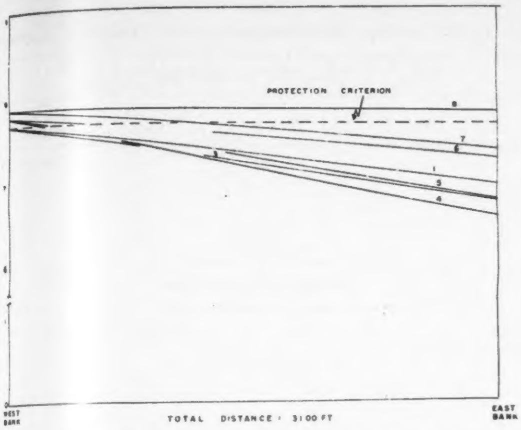

Figure 3—Pipe-to-soil voltage vs distance for the seven refinery underriver pipe lines to Anchorage Tank Farm. Note: This graph shows voltage measurements with the east bank rectifier turned on. The numbers on the curves indicate the number of the pipe line.

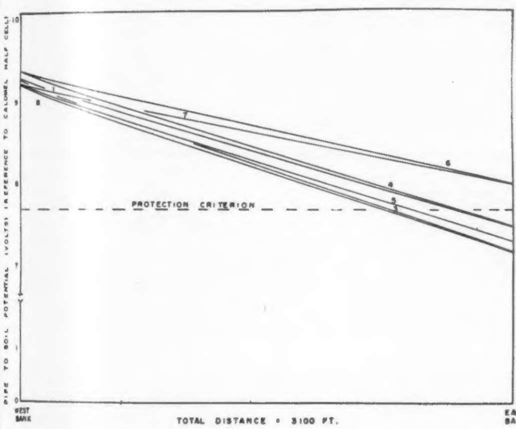

Figure 4—Pipe-to-soil voltage vs distance for the seven refinery underriver pipelines to Anchorage Tank Farm. Note: This graph shows voltage measurements with the west bank rectifier turned on. The numbers on the curves indicate the number of the pipe line.

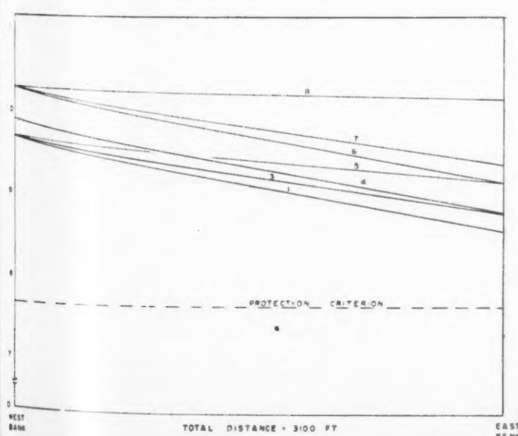

Figure 5—Pipe-to-soil voltage vs distance for the seven underriver pipe lines to Anchorage Tank Farm. Note: This graph shows voltage measurements with both rectifiers turned on. The numbers on the curves indicate the number of the pipe line.

river. The groundbeds were located to minimize the effect of the protective currents on other submerged structures in the immediate area without sacrificing protection of the seven pipelines. On the east bank, the groundbed was installed approximately 1000 feet north of the underriver pipelines. On the west bank, the groundbed was placed on the river side of the levee approximately 1500 feet south of the underriver pipelines. Placing the groundbed on the river side of the levee insured that the anodes would be in soil that would remain moist, thereby securing low soil resistivity with a resultant decrease in the required rectifier voltage.

Wiring

Considerable difficulty was experienced in obtaining cable in the sizes and with the type of insulation required by the specification of this unit, so some substitutions were made. No. 2/0 AWG stranded, copper cable was used in lieu of the No. 4/0 cable specified for the drain leads for lines on both the east and west banks and for the section of the main positive lead running from the rectifier under the railroad trestle to the first pole south of the trestle where connection was made to the No. 4/0 weatherproof insulated cable running overhead. The specification further called for thermoplastic insulation for all cable running underground but No. 2/0 cable with thermoplastic insulation was not available at the time of construction and a 30-week time had been set on delivery of this type of cable. In view of the delivery delay of thermoplastic insulated cable and the steady rise in the river stage which threatened to flood the installation site before construction could be completed, a test was run on cable with Okonite-Okoprene oil-resistant insulation which was immediately available. The insulation was exposed to varying concentrations of sulfuric acid in an attempt to simulate conditions present at the groundbed location on the east bank where acid sludge was mixed with the soil. Since no apparent damage to the insulation was observed after exposure of two weeks, the Okonite-Okoprene insulated cable was used in all locations requiring No. 2/0 cable and for a small portion of the 4/0 cable in the drain lead to adjacent pipelines belonging to a neighboring industry.

Electrical Connections

All connections of the anode leads to the main positive lead were made by wrapping the end of the anode lead around the main lead and soldering. Pressure-type connectors were used for all other connections on the positive side of the load circuit and for all connections on the negative side with three exceptions:

1) the drain lead connections to the pipelines which were made by the Cadweld process,
2) the drain lead connection to the power cable on the east bank which was made by welding, and
3) the drain lead connections to the telephone cable on both sides of the river which were made by soldering.

.All connections on the positive sides of the circuits were insulated by coating with one coat of a coal tar primer, placing the connection in a quart motor oil

can and filling the can with a hot applied coal tar mastic. All connections on the negative sides of the circuits were insulated by applying one coat of the above-mentioned primer followed by two coats of mastic.

Experimental Nature of Installation

In addition to furnishing protection to the pipelines and under-river cables involved, this installation is expected to provide information to be used in the design of future cathodic protection units. With this in mind, two parallel rows of anodes in the east bank groundbed were connected to the main positive lead so that they could be easily cut out of the anode system. This will permit study of the interference effect of the parallel rows of anodes and their effect upon the current distribution. A study also will be made of the shielding effect of those lines nearest to the groundbeds on other lines in the vicinity.

Legal Problems

The approval of the West Baton Rouge Parish Police Jury, the New Orleans District Engineer and the Board of Commissioners of the Atchafalaya Basin Levee District was secured for this installation and the permission of the Missouri Pacific Railroad Board of Trustees was secured to locate the west bank groundbed on railroad property. A permit was obtained from the State Department of Highways to lay the anode cable under State Highway No. 319 on the west bank of the river.

Because five 8-inch brine pipelines belonging to another industry cross the river in the protection area, this company was invited to participate in a joint cathodic protection program. They declined to take part in the project but requested that their five pipelines be bonded into the system to prevent stray current corrosion. These pipelines were bonded into the system with an AWG 4/0 copper cable drain lead connected in series with a variable resistor. The resistor was inserted in the drain lead to limit the current to these lines. They are not receiving full protection.

Results

To determine the effectiveness of this installation, pipe-to-soil voltage measurements were taken at the edge of the river before and after the individual rectifiers were turned on. (See Table I.) A pipe-to-soil potential of —.77 volts with respect to a calomel electrode, which is the voltage required for full protection of carbon steel in contact with soil, was used as the full protection criterion. With the east bank rectifier turned on and the west bank rectifier off, all pipe-to-soil voltage measurements on the east and west banks were increased, with those on the east bank in excess of (more negative than) —.77 volts; this was also the case with the east bank rectifier off and the west bank rectifier on. With both rectifiers turned on, all potential readings on both sides of the river were in excess of (more negative than) —.77 volts.

Straight line approximations of voltage distribution along the pipelines have been assumed since it is impractical to take potential readings away from each bank in the river (Figures 3, 4 and 5). While this assumption may not be absolutely correct, it is believed approximations are close enough to indicate the magnitude of potential at points on the pipelines.

TABLE I
Pipe-To-Soil Voltage Measurements on the Underriver Pipelines

BOTH RECTIFIERS OFF

Pipeline Number	West Bank (Volts)	East Bank (Volts)
1	—.685	—.580
3	—.680	—.530
4	—.680	—.480
5	—.690	—.535
6	—.680	—.520
7	—.670	—.530
8	—.680	—.550

BOTH RECTIFIERS ON

Pipeline Number	West Bank (Volts)	East Bank (Volts)
1	—.970	—.860
3	—.970	—.900
4	—.990	—.900
5	—.970	—.920
6	—1.030	—.920
7	—1.030	—.940
8	—1.030	—1.040

EAST RECTIFIER ON

Pipeline Number	West Bank (Volts)	East Bank (Volts)
1	—.770	—.700
3	—.770	—.680
4	—.780	—.660
5	—.780	—.700
6	—.780	—.730
7	—.790	—.740
8	—.790	—.785

WEST RECTIFIER ON

Pipeline Number	West Bank (Volts)	East Bank (Volts)
1	—.932	—.750
3	—.930	—.720
4	—.940	—.750
5	—.925	—.730
6	—.940	—.800
7	—.925	—.800
8	—.923	—.740

General

The first potential measurements indicated that protection was being achieved even though the pipelines on the east bank were not insulated from adjacent connecting lines or from the dock structure which lies south of the point where the underriver lines enter the water. A closer inspection of the current flow in the system revealed that approximately 60 percent of the applied current was being drained away from the dock structure proper rather than the pipelines. After the insulation of the underriver lines from connecting lines, another survey indicated current was being retained in the system. The readings discussed above are the most recent obtained and were taken with the pipe system isolated from adjacent lines and structures.

Potential measurements taken on adjacent lines indicate that the negative voltage with respect to a calomel electrode was greater after the lines were bonded into the system. This change was in the magnitude of 0.02 to 0.05 volts. This has borne out the belief that some slight increase in negative potential would be gained when the additional pipe system was bonded into the underriver pipeline cathodic protection unit.

Studies on Water-Dependent Corrosion In Sweet Oil Wells*

By H. E. GREENWELL

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Abstract

It has been known for a number of years that corrosion problems occur in the operation of sweet oil wells. General recognition of this fact has been brought about recently as a result of concerted efforts of the NACE TP-1 Committee. It is the purpose of this paper to summarize the present understanding of sweet oil well corrosion problems and to discuss means of detection and control. The greater part of the data which support the views given in the paper have been collected by the TP-1C Subcommittee on sweet oil well corrosion and by various individuals associated with the TP-1 Committee work.

It has been established that two distinct types of corrosion occur in sweet oil wells. One type, which has been known as "high pressure corrosion," occurs in wells producing as little as 0.1 percent water. The other type usually occurs in lower pressure wells and is related to a critical percentage of water production. This paper considers both types of sweet oil well corrosion with regard to the causative agents, controlling physical factors, statistics of occurrence and severity and control measures. Emphasis is placed on the most recent developments in the studies of "low pressure" or water dependent type of sweet oil well corrosion.

Introduction

IT HAS been recognized[1,2] recently that there are two distinct types of corrosion associated with the operation of sweet oil wells. The terms "high pressure" and "low pressure" sweet oil well corrosion have been used to differentiate between the two types of attack. Apparent features which have distinguished "high pressure" corrosion from "low pressure" corrosion are these: In the first class, corrosion usually is present from the beginning of production. Severe attack occurs when as little as 0.1 percent water is produced and the rate of corrosion does not appear to vary appreciably as the percentage of water increases. On the other hand, "low pressure" wells usually can be produced for years with no trouble. When corrosion does appear in the "low pressure" wells it is quite severe and tubing lives of less than one year have been observed. Studies have shown that, apparently, corrosion starts only after some critical water-oil ratio has been exceeded. The work of the National Association of Corrosion Engineers Technical Practices Committee[1] has done much to bring about general appreciation of these problems. It is the purpose of this paper to discuss recent progress in studies of "low pressure" wells by Subcommittee TP-1C on Sweet Oil Well Corrosion, a part of TP-1.

Recent work has confirmed the belief that the relation of corrosion to water production is an important feature which distinguishes "high pressure" corrosion from "low pressure" corrosion. So it is suggested that the terms "water-independent" (high pressure) and "water-dependent" (low pressure) corrosion are more descriptive terminology. This nomenclature will be used in this paper.

The TP-1C Subcommittee was founded to study the corrosion problems of sweet oil wells. Because of the magnitude of each of the two recognized types of sweet oil well corrosion, it was the collective opinion of committeemen that both could not be studied effectively at the same time. The decision was made to study the problem of water-independent corrosion first. The choice was made principally because of the insidious nature of this type of attack, the dangers resulting therefrom and the obvious economic stakes. Previous papers by Bilhartz[1,2] have summarized the subcommittee's efforts toward solution of this problem.

After substantial progress had been made in the study of water-independent corrosion, subcommittee effort was directed toward investigation of the water-dependent type of corrosion. This problem proved to be of large economic significance also. Preliminary studies have indicated that 30 percent of the country's low pressure sweet oil wells are economically affected by corrosion. For purposes of these studies, wells having an annual corrosion cost of $200 or more are considered corrosive. The annual cost of corrosion for each corrosive well has been estimated at $960 even with remedial measures. The average corrosive well experienced eleven years of relatively trouble-free operation before corrosion set in. After corrosion started, tubing life was reduced to an average of three years and tubing lives of as low as six months have been reported. This average corrosive well is produced from a depth of 5050 feet and has a bottom hole pressure of 2275 lb/in^2 and a bottom hole temperature of 160 degrees F.

Using these facts as a basis, the subcommittee has undertaken to define water dependent sweet oil well corrosion in terms of its empirical characteristics, causative agents, mechanism of attack, analytical

* A paper presented under the title "Corrosion in Sweet Oil Wells" at the Ninth Annual Conference, National Association of Corrosion Engineers, Chicago, Ill., March 16-20, 1953.

criteria and relationship to production techniques. Evaluation of remedial measures also forms an important part of the subcommittee's objectives.

Relation to Water Production

Early studies of low pressure wells were directed toward their most apparent characteristic—the dependence of corrosion on water production. No particular correlation was found between volume of water produced and corrosion. However, only a small proportion of the wells producing less than 40 barrels of water per day were corrosive, while 75 percent of those making greater than 100 barrels of water per day were corrosive. The distribution of corrosive and non-corrosive wells between the limits of 40 and 100 barrels of water per day appears to be random, as might reasonably be expected. While this information has little value to the problem of prediction, it does give insight into the economics of operation and treatment. Wells making large amounts of water usually have high lifting costs and the added burden of corrosion expenditure can sometimes result in operation at a loss. In many high water production fields, down time results in loss of production, so that cost of repairing corroded equipment is not the only economic loss. Inhibitors must be effective in very low concentration when large quantities of water are produced and the mechanical problems of treating are more difficult in many such cases.

While the amount of water production did not prove to be of particular significance to the problem of prediction, comparison of corrosion experience with percentage water resulted in a striking pattern. Composite figures, covering all of the corrosive fields studied, are as follows:

Percent Water	Percent of Wells Corrosive
0-20	0
20-40	1.8
40-60	44
60-80	25
80-100	85

From this brief summary, it may be inferred that there is a critical water-oil ratio below which corrosion does not occur. Apparently, this ratio is greater than 40 percent water for most fields.

The following pattern results when the statistics of a single field are tabulated:

Percent Water	Percent of Wells Corrosive
0-20	0
20-40	0
40-60	56
60-80	100
80-100	100

Another field has this pattern:

Percent Water	Percent of Wells Corrosive
0-20	0
20-40	0
40-60	67
60-80	100
80-100	100

A third field gives this pattern:

Percent Water	Percent of Wells Corrosive
0-20	0
20-40	33
40-60	100
60-80	100
80-100	100

Thus, it can be seen that the water-oil ratio has a primary influence on whether or not damage will occur to a given well in a corrosion-susceptible field. The factors which are thought responsible for this behavior will be discussed later in this article.

Controlling Factors

It is apparent these factors have given a much clearer picture of the cart than of the horse. What constitutes a corrosion-susceptible field?

At present, there is no precise answer to this question. However, the problem is thought to be understood in its general aspects. As in any system, there must be both ability and opportunity for corrosion to occur. It is believed generally that the corrosion tendency, or ability, is provided by the traditional causative agents, i.e., carbon dioxide and fatty acids, amounting to an acid pH in the well. Carbon dioxide appears to occupy the primary role because of the pitting attack it produces. No insoluble primary corrosion products are formed and the rate of reaction does not decrease with time. The part which fatty acids play is somewhat less certain. Fatty acids content of the order of 1000-1500 ppm (as acetic acid) have been reported from wells suffering severe corrosion. These relatively high fatty acids concentrations were accompanied by low partial pressures of carbon dioxide. However, as a general rule, it is believed that fatty acid content usually lies at a much lower figure in wells which have had corrosion. It is quite probable that there is an analogy with condensate well corrosion, where fatty acids are regarded as a contributing rather than a primary, factor.

Water-dependent sweet oil well corrosion is not without its exceptional cases. Widespread, severe corrosion has been reported in one field, where neither carbon dioxide nor fatty acids have been detected. Other, less well defined instances of this unexplained behavior have been noted. As a result, there is a growing body of belief that there are additional undiscovered corrosion causative agents in some production. Private investigation by a few individuals has been unfruitful. The difficulties of investigating such a question cooperatively at this time are apparent. Much work remains to be done on the subject of causative agents.

The opportunity to corrode is governed by the factors which permit the steel to be wet by the corrosive water. These appear to be the wetting tendency of the oil and the relative amount of water present. All oils possess the wetting property to some extent. This wetting tendency, whether it be great or little, does not appear to vary with the percentage of oil. However, with a given wetting tendency, the film of protective oil will be overcome at some ratio of water to oil. Undoubtedly, there are complicating factors such as mechanical scouring which cannot be measured readily. The so-called

critical water-oil ratio to produce corrosion will vary widely from field to field, even though the same amounts of causative agents may be present. It is conceivable that a field might never be economically corrosive even though all the causative agents were present in sufficient concentration.

Analytical Criteria

It is logical to attempt to define the severity of a corrosion problem in terms of the concentration of its causative agents. Although work has been undertaken to establish prediction criteria on this basis, there are insufficient data now to justify formulation of general rules. It is not expected this will be an easy task, particularly with regard to carbon dioxide. It will not be possible to correlate corrosion directly with percentage or partial pressure of this gas, as was done with condensate wells. In condensate wells, the problem involved fresh water where the ratio of gas volume to water volume is very large. The concentration of carbon dioxide in the gas, then, was a reliable index of downhole acidity. The situation is much less straightforward in an oil well. The volumes of gases and water are more nearly equal and both must be taken into consideration. Solubility and ionization of carbon dioxide in a complex brine is governed by other factors in addition to temperature and pressure. Down-hole pH in an oil well cannot be inferred from the concentration of carbon dioxide in the gas sampled at the surface. The pH can be determined only by calculations which are, at present, somewhat elaborate and inexact or by use of special apparatus in the laboratory. Thus, it is seen that knowledge of the concentration of known causative agents does not furnish a reliable criterion of prediction.

While a considerable amount of work has been done in attempts to relate the iron content of a produced water with corrosion, to date no generally applicable criterion can be presented. This is a somewhat surprising development. When corrosion occurs, iron is dissolved and it would be expected that the amount of iron loss would be susceptible of simple correlation. It will be understood that by "amount" is meant some quantity such as pounds per day and not ppm. With a few exceptions, no such correlation has been developed. Analyses have shown that the iron production from a group of known corrosive wells will vary from inappreciable amounts to several pounds per day. An equally wide variation in the same well stream has been found. In cases when the apparent iron production is reasonably consistent, 0.5 lb. iron per day can signify severe corrosion in one field, while five pounds per day in another field may be little cause for alarm.

There are several probable reasons for this disappointing situation. It is well known that many shallow water sands have high concentrations of iron in the form of ferrous bicarbonate dissolved in the water. More and more evidence is being obtained leading to the conclusion that deep strata are similar in this respect. It must be admitted then that, in any well producing bottom water, iron of "natural" origin may be produced.

Another important variable universally recognized but seldom acted upon is the necessity of having representative samples. Frequently, several days' work is required to obtain one truly representative sample of well effluent. Application of exacting sampling procedures on a useful scale is beyond the reach of practically all investigations. On the other hand, reasonable care will yield useful samples in many cases. In any event, the practice of obtaining samples in the easiest possible manner enjoys wide currency. There are certain inherent faults with wellhead sampling which must not be overlooked. At many wellheads, the pH has risen to a value which accompanies the conversion of soluble ferrous bicarbonate to much less soluble ferrous carbonate. In these cases, "total" iron determinations are not total at all with respect to the well stream. Handling of the sample after it has been collected, method of analysis and manner of reporting data also are important.

The time-honored coupon technique has not fared well in application to sweet oil well corrosion investigations. Not many instances of the successful use of flow line coupons have been reported. The principal reason for this result is inherent in the characteristics of the well. Most sweet oil wells simply are not corrosive at the surface and this fact alone is strong proof that carbon dioxide probably is the principal causative agent. Results of coupon exposures also are influenced by the technique employed and by such factors as temperature, paraffin deposition and dissipation of the corrodent.

Coupon studies have been redeemed to an important extent by favorable results obtained by some operators who have exposed specimens at various depths in wells. One very serious, widespread case of corrosion was discovered during the past year through this method. By all indications at the surface, the wells were non-corrosive. It is interesting to examine the coupon data. Rates of coupon corrosion in two wells were as follows:

Depth Feet	Well No. 1 IPY	% Water
6000	0.0479	55
4000	0.0194	55
2000	0.0068	55
	Well No. 2	
6000	0.0212	10
4000	0.0025	10

Subsurface exposure of coupons is, of course, not the simple problem that flow line coupons present. However, until it is possible to predict corrosion from data which can be obtained at the surface, coupons will play a valuable part in the study and control of sweet oil well corrosion. Details of this useful technique have been presented elsewhere[3] and need not be discussed here.

Attempts have been made to relate the wetting power of an oil and corrosion but so far success has been achieved only in a general sense. On one hand most cases of corrosion have been shown to be associated with oils of poor wetting ability and on the other oils of good native wetting power are known to occur in fields which are non-corrosive. Work on this aspect of the problem has not progressed to the point that critical water-oil ratios can be predicted

from wettability data. Studies of specific fields have shown that the protection afforded by the oil is clearly a function of the percentage of oil in the well stream. Using this as a basis, it should be possible to derive more general conclusions when sufficient data become available.

Metallurgical Factors

No corrosion problem is independent of the properties of the metal being corroded. The discussion thus far has led to the conclusion that the phenomenon of sweet oil well corrosion is largely governed by the wetting (protective) power of the oil and corrosive properties of the water. Metallurgical factors upset this view to some extent. Severe "ring worm" attack of tubing has been observed in wells producing approximately 30 percent water. Normally, wells in this field must reach 50 percent water before corrosion begins. The wells in which the "ring worm" attack took place had no other significant corrosion damage. Serious attack of macaroni strings employed in certain gas lift schemes has been experienced. These wells suffered no corrosion of other in-hole equipment and the problem was eliminated by removal of the macaroni strings. Small sizes of pipe have been troublesome from the corrosion aspect for many years. A better understanding of the properties desired to reduce corrosion susceptibility has led to significant reduction of these troubles. It is probable that, through utilization of metallurgical know-how and better mechanical design, building corrosion into installations shall cease. In any event, it is clear that improper metallurgy may upset an otherwise corrosion-free situation.

Relationship to Method of Production

There has been wide interest in the influence of method of production on water-dependent sweet oil well corrosion, but no clear-cut relationship has been established yet. It appeared for some time that the use of gas lift aggravates the corrosion process and causes corrosion to begin at lower water-oil ratio than would be expected from experience with flowing wells. This conclusion appears to be sound in a few fields but it cannot be applied generally. Further investigation has shown that, in most cases, water production, corrosion, and method of production are so interrelated that they cannot be considered independently. Final evaluation of the effect of gas lifting must be withheld until more data are available.

Other Influencing Factors

Certain other factors which must be considered in a discussion of sweet oil well corrosion have been noted. A clue to the engineer trying to anticipate corrosion is the observation that oil wells associated with corrosive gas production usually are corrosive. The corrosion tendency of the reservoir is disclosed early in the life of the gas wells. The oil wells become susceptible only when the oil no longer affords protection to the steel. Thus, forewarned, the oil wells will be observed with the belief that corrosion is almost inevitable sometime during their life. When it becomes possible to predict both reservoir performance and the critical water-oil ratio, corrosion can be anticipated long before it occurs.

It has been observed also that even after corrosion begins it is by no means in unvarying quantity. In addition to the expected variables of rate of production, percentage of water, temperature and pressure, some fields have a peak of corrosiveness. Corrosion starts, increases to a maximum and then declines. Perhaps a careful analysis of each case would show this behavior results from the combined effects of several changing quantities. Gas-oil ratio is believed to be significant to the corrosiveness of wells and in numerous instances corrosion is more pronounced as the GOR increases. This might be regarded as more proof that carbon dioxide is the principal causative agent. Perhaps gas-water ratios in a field will be found to correlate better with corrosiveness than gas-oil ratios.

Preventive Measures

It is fortunate that the effective application of protective measures does not depend solely on complete understanding of the cause of attack. Several successful methods have been developed on the basis of "common sense" and application of the facts which have been established. Present control measures undoubtedly will become more economical as a better understanding of all the variables is obtained and it is probable this understanding will result in improved methods.

Among chemical inhibitors which are the most widely employed preventive measure, the class of chemicals known as adsorptive-type inhibitors is in greatest use. An interesting variety of techniques of application has been reported.

One operator solved the problem of treating a large group of wells by injecting inhibitor into the gas lift system. Adsorptive-type chemical is batched into the lines daily, the amount used governed by water percentages as follows:

Percent Water	Qts. Chemical per Day
50-65	½
66-75	1
76-80	1½
80	2

This treatment has been in effect since late 1949 and caliper surveys and history of failure have shown that good protection has been obtained. None of these wells is equipped with a packer.

Another operator found a similar procedure unsatisfactory in a group of gas lift wells equipped with packers. This group of wells produced 80 to 90 percent water. In-hole coupon exposures showed excellent protection was gained in the tubing down to but not below the bottom valve.

One company experienced an unusual set of circumstances which made development of a suitable stick-type inhibitor an attractive possibility. Severe corrosion was experienced in a group of flowing wells. These wells were extremely susceptible to sanding-up and experience had shown that a packer was a necessity. No commercially available stick would dissolve in the proportion of oil and water being produced and bottom hole temperature of 140° F would not melt them. A truly water-soluble stick

incorporating a rosin derivative inhibitor was made. After using this stick in two corrosive flowing wells for eleven months, it appeared that this particular stick is an economic failure. Apparently successful use of commercial sticks in wells having sufficiently high bottom temperature has been reported for a relatively large number of wells. The frequency of treatment and the shut-in time following treatment varies widely in practice and no generalization can be drawn as to the optimum technique. In general, stick treatment appears to be more expensive than application of liquids.

The use of adsorptive-type inhibitors in some cases has resulted in unexpected benefits from other quarters. Certain of these compounds have proved to be quite effective as emulsion treating chemicals. In instances, additional treatment to remove water has become unnecessary. There is some belief that adsorptive type inhibitors have a certain detergency toward paraffin and it has been reported also that fluids treated with inhibitor are less viscous than normal, with such results as lowered stuffing box pressure in a pumping well. It has even been stated that this type inhibitor has lessened deposition of mineral scales. While none of the foregoing can be accepted as being applicable to any other location without careful substantiation, they are of more than casual interest. If any one of the above results could be obtained in a corrosive field, the economics of controlling the corrosion would be changed considerably. There is little basis upon which to anticipate such an occurrence, but these effects can be watched for when an inhibitor program is put into effect. If one of the added benefits is obtained, it may permit a more effective corrosion control program because of reduced operating costs.

The fact that water-dependent sweet oil well corrosion appears to be closely related to the wetting properties of the oil is suggestive of a means to control the corrosion. The idea was conceived several years ago that it should be practical to increase the wetting power of an oil by adding the proper wetting agent with the expectation the produced oil then would furnish protection to the equipment, thus, in effect, increasing the critical water-oil ratio. An article dealing with this subject was published in 1947.[4] Although not reflected in the literature, notable progress has been made in practical application of this method since.

The "drop-size ratio" technique is used to measure the native wettability of the oil and the improvement of wettability resulting from the addition of wetting agent to the mixture. The drop-size ratio measurement may be described very briefly as follows: A very small drop of oil is released in a cell filled with the produced water and held captive under a small steel plate immersed horizontally in the water. The shape of the captive drop will depend on the degree to which it wets the steel surface. The drop will be perfectly spherical if there is no wetting. The drop will flatten, or spread out, according to the wetting power of the oil. The flatter the drop, the more oil wetting is taking place.

The degree of flatness required for suitable protection has been determined through extensive experiments. Various wetting agents or combinations of agents are tried until the formula which gives the most economical drop size reduction is found. Field experience with this approach has demonstrated that treatments chosen in the laboratory work well in actual application. While taking fully into account the complexities of the drop-size ratio technique, it is obvious this method is much less cumbersome than the indirect evaluation methods required for other types of inhibitors. It is possible to write a "prescription" for the well in advance and the economics of treatment are known before any chemical has been used. Another advantage of the wetting agent approach is that, frequently, the minimum phase (the oil) is being treated. If the oil is responsive to treatment, the economics seldom become unfavorable due to increasing volume of water.

A possible disadvantage to the immediate widespread commercial application of this procedure lies in the complexity of the wetting phenomenon. Many agents must be tried for each system and specialized equipment and procedures must be employed. There is no universally good wetting agent and each problem must be considered individually. Until several more years experience has been gained, a great amount of control work probably will be required for effective use of wetting agents.

Further investigation of wetting agent behavior is being made in several laboratories. Different types of agents and combinations of agents are being studied. It should be expected that knowledge of this subject will be broadened considerably in the near future.

Conclusion

In summarizing the problem of water-dependent sweet oil well corrosion, it appears to be controlled by two factors: The ability to corrode and the opportunity to do so. Ability is determined by the concentration and behavior of causative agents in the well. Opportunity is governed by the native wetting tendency of the oil and the proportion of oil and water at which the film of oil on steel is overcome. The cumulative effect of these factors is that corrosion of this type appears in a well when a critical water-oil ratio is exceeded.

Upon this basis, the NACE Subcommittee TP-1C is performing an industry wide study of the corrosion problems of sweet oil wells. The corrosion history of every field operated by the participating companies is being compiled. Fields for specific study will be chosen from this information, and further investigation of each aspect discussed in this paper will be carried out by the subcommittee.

Acknowledgment

This paper was written in acknowledgment of the efforts of TP-1C Subcommittee. Particular appreciation is due Jack L. Battle and R. C. Buchan of the Humble Oil and Refining Company, H. E. Waldrip of the Gulf Oil Corporation, and W. H. Edwards of the Superior Oil Company for contributing valuable material for the paper.

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DISCUSSION

Discussion by W. H. Edwards, Superior Oil Co., Houston:

With reference to the use of coupons I would like to point out a few things that I believe are of interest. Although Mr. Greenwell presented a very good paper on the preparation of coupons at a previous NACE meeting, we continued coating our coupons with petroleum jelly. We found in one field in South Texas that such coupons apparently retained an oil wet surface from the petroleum jelly which in some cases reduced the rate of corrosion as compared to water wet coupons by as high as 90 percent on 5 to 6 weeks' exposure. This difference was most noticeable in a corrosive well with higher cuts. One well in this same field that has been cutting 10 percent since completion 2½ years ago has just been calipered. Coupons set in the tubing at 6000, 4000 and 2000 feet indicated a high rate of corrosion at the bottom becoming progressively less up the tubing, but the caliper indicated very little corrosion below 5100 feet, up to 40 percent wall reduction between 5100 and 3600 feet and progressively less above 3600 feet. A well cutting 55 percent and total fluid of 300 bbl./day with a bottom hole coupon corrosion rate in excess of .04 IPY is being treated with a stick inhibitor. Although the reduction of iron in the produced water is negligible (20 down to 18 ppm), coupons have indicated better than 90 percent protection with this treatment.

In another field (South Louisiana) where the corrosion was found to be serious after the water produced exceeded 50 percent, both coupons and caliper surveys indicated that the corrosion was most severe at the bottom becoming progressively less all the way to the surface. The corrosive wells in this field are being treated with a stick type inhibitor. One well producing in the neighborhood of 1000 bbls./day with a 90 percent cut has been satisfactorily protected with 3 sticks every other day. Previous to this treatment down hole coupons had indicated corrosion in excess of .02 IPY. Several wells in this field are being treated without shutting in the well. The sticks in all wells are chased with a wire line tool at least once every 4 to 6 weeks to insure their going to bottom.

Corrosion of Casing in Oil and Gas Wells ★

By JACK L. BATTLE

Introduction

THE PRODUCTION or oil string casing in oil and gas wells is that thin-walled metal cylinder which is intended to maintain the original hole for the productive life of the well. In the early history of the petroleum producing industry with uncontrolled production rates it was assumed that the casing would last the productive life of the well so little consideration was given to possible damage from corrosion in the design of these casing strings. In fact, until recently the casing string was designed primarily to withstand tensile and collapse failures with minimum safety factors. With proration reducing flow rates to prolong the productive life and increase the ultimate recovery from today's oil fields, the corrosion of this equipment is receiving more serious consideration.

At the close of 1951, the American Petroleum Institute reported 482,260 producing oil and gas wells within the United States. Although the maximum productive depth at that time was 15,530 feet, the average depth of the productive wells was 3888 feet. A conservative estimate of the steel used in the production string (assuming 7-inch OD 29-pound per foot casing) of these wells is approximately 27 million tons which, at today's prices, is worth some $5 billion. Casing failures are occurring in many wells of the older fields as well as in some of the newer fields at a time when only a part of the recoverable reserves have been produced. The wells which must produce these reserves represent tremendous investments. Because of the vigorous and prompt prosecution of remedial work by the industry when casing failures have occurred, major damage to a reservoir has seldom actually occurred. Nevertheless, the potential damage to a reservoir in such cases is great.

Repair of such failures often can be made only by setting inside liners, the cost of which frequently approaches the original cost of the well. In some few instances, repair takes the form of redrilling the well which, at today's drilling costs, may not be economically feasible in the case of some of the poorer fields. Thus, unless the oil is produced by adjoining wells, such failure can result in the loss of recoverable oil.

The corrosion of this vital member of the subsurface equipment of an oil or gas well presents a most complex problem and a challenge to the corrosion engineer. He is unable to examine the member in most instances until the damage is done. He must rely on caliper surveys which can be run only when the tubing is out of the hole to determine the internal condition of the pipe and must rely on

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Abstract

In January, 1952, there were 482,260 producing oil and gas wells in the continental United States, having an average depth of 3888 feet. Assuming 7-inch OD 29-pound casing, these wells were equipped with approximately 27 million tons of steel in the oil string, having a present-day replacement cost of about $5,000,000,000. These wells should produce crude oil reserves estimated at 26 billion barrels plus some 4.5 billion barrels of natural gas liquids.

A limited polling of companies participating in NACE Committee TP-1H activities indicates that in fields in which only 45,830, or less than 10 percent, of these wells are located, repair of casing due to corrosion failure is costing these companies in excess of $2,000,000 annually at the present time. This is exclusive of loss of production due to downtime, premature abandonment of isolated wells and factors of a less tangible nature. Obviously, the total loss to industry is great and can only be estimated.

This paper discusses the various causes of such corrosion failures, the presently used methods of repair and preventive measures currently being practiced. The results of a survey of one operator's experience over a 10-year period is drawn upon in some detail.

failure frequency, well history and workovers to learn the external condition of the pipe.

In view of the obvious seriousness of the problem, National Association of Corrosion Engineers' Technical Practices Committee 1 in 1951 organized Subcommittee TP-1H on Corrosion of Oil String Casing to study the problem in detail. Much of the data presented in this paper is the work of this subcommittee and the participation of all its members is hereby acknowledged.

Previous Investigations

Among the early investigators who recognized the industry's problem were Bailey and Crowell,[1] who describe the damage to casing in the Magnolia, Arkansas, area, which produces a sour or sulfide-bearing crude; and Ewing and Bayhi,[2] who reported the results of work in the Loudon Pool of Illinois to correct a serious problem of electrolysis resulting from differential aeration of the flow line and casing.

TABLE I
Oil String Casing Corrosion
Summary of Questionnaire Replies from Participating Members National Association of Corrosion Engineers Committee TP-1H

AREA—FIELD	County	Producing Formation	Producing Depth, Feet	CHARACTERISTICS OF FLUIDS PRODUCED — Crude		Water		Gas-Oil Ratio, CFB	Gas Analysis Percent		Total Number Wells in Field, 1951	REPORTED BY COMMITTEE MEMBERS		
				Gravity	Sulfur	Total Solids, ppm	H_2S, ppm		H_2S	CO_2		Operated in Field	Failures 1949-51	Percent
EAST TEXAS:														
East Texas......	Gregg, et al	Woodbine	3,500-3,800	38°	Sweet	61,000	....	....	....	....	29,293	688	1	0.14
East Texas......	Gregg, Rusk	Woodbine	3,500-3,800	38°	Sweet	60,500	....	350	None	2.3	29,293	1,384	11	0.80
East Texas......	Gregg, Rusk	Woodbine	3,500-3,800	39°	Sweet	67,000	....	300	....	....	29,293	2,615	35	1.3
Talco...........	Titus, Franklin	Trinity (Paluxy)	4,200-4,300	22°	Sour	17,400	Trace	25	Less than 0.1	3.6	889	271	10	3.7
GULF COAST:														
Fannett.........	Jefferson	Miocene Frio, Marginuline	4,300 8,250	31-36°	Sweet	95,000	None	250-3,100	....	0.6	154	58	2	3.4
Hankamer......	Liberty	Frio, Miocene	1,990-7,100	24-33°	Sweet	87,000	None	300	....	....	92	22	2	9.1
Magnet-Withers.	Wharton	Frio	5,520-5,550	25.6°	Sweet	....	....	1,000-1,800	....	0.3	421	139	1	0.7
Moores.........	Fort Bend	Miocene, Frio, Yegua	2,250-7,700	28.5°	Sour	26,000	25	239	....	....	49	19	1	5.3
Tomball........	Harris	Cockfield	5,400-5,600	40°	Sweet	65,000	None	1,200	....	....	545	380	9	2.4
NORTH TEXAS:														
Montague.......	Montague	......	870-890, 1,360-1,378	....	....	....	....	....	....	....	......	......	....	....
Panhandle......	Gray, et al	Wolfcamp Dolomite	3,000	40°	Sour	....	....	....	0.5	....	9,000	583	1	0.17
SOUTHWEST TEXAS:														
Colorado........	Jim Hogg	Cockfield	3,100	46°	Sweet	32,000	None	400	....	....	245	118	9	7.6
Darst Creek.....	Guadalupe	Edwards	2,600	37.5°	Sour	27,000	580	Negligible	13.3	22.7	388	57	1	1.8
Flour Bluff......	Nueces	Frio	6,600-6,800	41°	Sweet	68,000	None	1,500	....	....	117	114	6	5.3
WEST TEXAS														
Hobbs..........	Lea N.M.	San Andres	4,175	35°	Sour	19,000	....	699	....	....	267	9	1	11.1
Jordan..........	Ector	San Andres	3,300	34.5°	Sour	Salt	....	600	2.8	0.2	257	31	2	6.5
Keystone-Colby..	Winkler	....	3,300-3,350	35.5°	Sour	....	....	....	....	....	423	15	1	6.7
Means..........	Andrews	Grayburg	4,400	27°	Sour	38,000	485	520	5	6.9	233	179	3	1.7
Monument......	Lea, N.M.	Grayburg San Andres	3,900	32.0°	Sour	....	Present	2,200	4.8	1.7	1,004	21	2	10.5
Monument......	Lea, N.M.	San Andres	4,000	30.5°	Sour	....	Trace	....	....	....	1,004	42	2	4.8
Penwell.........	Ector	San Andres	3,300	34.5°	Sour	....	....	580	3.2	0.1	203	10	1	10
Penwell.........	Ector	San Andres	....	37.0°	Sour	....	....	....	High	....	203	17	1	5.9
TXL...........	Ector	Ellenburger	9,500-9,800	Sweet	crude	....	Trace	....	Unknown	....	160	23	1	4.3
Vacuum........	Lea, N.M.	San Andres	4,700	37.4°	Sour	....	Trace	650	....	....	415	87	1	1.2
Wasson "5100"..	Gaines, Yoakum	San Andres	5,100	33.0°	Sour	....	Present	1,730	0.15	6.0	1,641	238	18	7.6
MISSISSIPPI:														
Baxterville......	Lamar	Tuscaloosa	7,600-7,800, 8,600-8,750	16°	Sweet	....	....	....	....	1.2	34	6	1	17

a—Flow line current measured 2.8 amperes after failure.
b—Acidic gas in vapor space of annulus.
c—Production string exposed to salt section.

Little additional information is available in literature on the specific problem of casing corrosion.

Magnitude of Problem

A recent survey was conducted by the Subcommittee TP-1H to determine the extent of the problem. The committee members submitted data on 123 casing failures which occurred in some 22 fields during the years 1949 through 1951. In these 22 fields, the members operated 7126 of the 45,830 field wells involved and reported repairs to have cost $867,256. A summary of these data is shown in Table I. Assuming the same failure frequency by nonparticipating companies in the fields covered, the number of failures may be estimated at 646 and the cost of repair at approximately $6,600,000. Similar extension to all fields within the United States is not practical or justified but the magnitude of the problem should be evident. Its solution should have a significant bearing on the cost of producing oil in the future.

One participant in the above-mentioned committee activities made an extensive study of all casing failures due to all causes occurring in its rather

TABLE I
National Association of Corrosion Engineers Committee TP-1H
Oil String Casing Corrosion
Summary of Questionnaire Replies from Participating Members

AREA—FIELD	Average Age of Wells at Failure, Years	Depth of Failure, Feet	Apparent Cause	METHOD OF REPAIR				COST, DOLLARS			Remarks
				Cement	Packer	Patch	Liner	Average	Maximum	Total	
EAST TEXAS:											
East Texas......	18	116	Unknown	....	....	....	1	......	......	......	Severe external pitting from 90 to 300′.
East Texas......	16	175-310	Stray Current	....	....	....	1	4,130	11,120	45,390	Four leaks occurred about 2,200′, remainder about 300′.
East Texas......	16.9	175-325	Acid Water	23	3	9	....	3,120	8,900	99,200	No significant flow line current or subsurface currents observed.
Talco....	11.3	1,252, 1,500, 3,120	Stray Current	7	2	....	1	3,200	12,000	32,000	Insulating flanges installed in 1949 has reduced number of failures.
GULF COAST											
Fannett........	10.5	1,876	External—Acid Water	2	...	....	....	9,120	......	20,573	Casing leaks occurred in cap-rock of Fannett salt dome.
Hankamer......	20	3,805	Unknown	2	......	....	....	15,000	17,000	30,000	Heavy casing program possibly cause of few failures in this field.
Magnet-Withers.	10.5	2,349-5,495	Salt water and gas-lift[a]	1	....	....	....	11,173	11,173	11,173	One well abandoned due to collapse of casing on squeeze job.
Moores.........	18	500	Unknown	1	......	....	....	5,272	......	5,272	Leak believed caused by internal corrosion.
Tomball........	10.5	3,877, 4,384	Stray Current	8	......	1	....	9,400	12,300	84,600	Casing potential profiles indicate currents leaving casing in area of failure.
NORTH TEXAS:											
Montague......	25	350, 562, 950	....	......	2	....	....	......	......	......	....
Panhandle......	......	......	Stray Current	......	......	....	1	6,600	......	6,600	....
SOUTHWEST TEXAS:											
Colorado.......	10	1,500-1,600	Possibly Bacteria	1	2	1	5	2,170	2,916	19,500	No significant flow line or subsurface currents found present.
Darst Creek.....	19	797	Unknown	1	......	....	....	......	......	......	Believed caused by acid gas in vapor zone. Well Plugged and abandoned.
Flour Bluff......	8.9	3,300	Stray Currents	5	1	1	....	8,720	17,600	52,300	Insulating flanges installed in 1950 has resulted in decrease in number of failures.
WEST TEXAS:											
Hobbs..........	21	2,045	External	1	......	....	....	5,416	......	5,416	Caliper survey indicates no internal corrosion.
Jordan.........	12	1,400	Acid gas[b]	......	......	....	2	20,000	23,000	40,000	Casing now protected by injection of organic inhibitors.
Keystone-Colby..	7	1,009-1,040	Salt water	1	......	....	....	2,494	......	2,494	....
Means..........	7.2	3,480-3,497	Internal	1	......	....	2	15,000	21,850	45,200	Recovered casing shows no external attack in area of failure.
Monument......	14.2	515, 610	Acid gas[b]	......	......	2	....	6,000	7,000	12,000	Casing caliper—severe corrosion, 0-600′; casing-tubing annulus now loaded with crude oil to exclude corrosive gas.
Monument......	16	600-1,500	Salt section	2	......	....	....	10,700	......	21,400	....
Penwell.........	18	1,200	Acid gas	......	......	....	1	10,300	......	10,300	Casing now protected by injection of organic inhibitor.
Penwell.........	12.5	2,073	Salt water	1	......	....	....	9,888	......	9,888	Casing caliper indicated 10-30% wall reduction. 2,100-2,335′.
TXL...........	6	3,856-5,012	Unknown	1	......	....	....	20,700	......	20,700	....
Vacuum........	7	1,778-1,782	Internal[c]	1	......	....	....	16,300	......	16,300	....
Wasson "5100"..	11.9	1,215, 1,650	Acid gas	13	......	5	....	20,200	30,000	225,000	Casing-tubing annulus now loaded with organic inhibitor and crude.
MISSISSIPPI:											
Baxterville......	5.75	4,935-5,060	Possibly tubing wear	1	......	....	1	......	......	51,950	Leak in same well in 1947 at 4,528-63′ which was cemented off.
				73	10	19	15				

widespread operations during the 10-year interval 1941 through 1950. An analysis of well completion and workover records, visual examination of recovered equipment, the analysis of produced fluids, flow line current surveys and internal casing calipers usually provided sufficient information to determine the actual cause of failure in all but a very limited number of cases. The study revealed that 79 percent of all such failures could be attributed to corrosion. The remaining 21 percent occurred as a result of mechanical failures, erosion failures and failures from unknown causes. Most failures resulted from external corrosion of casing by formation waters that had not been confined by cement or mud or neutralized by alkaline muds. Other prominent and contributory causes revealed by the study were the flow of stray currents and contact with acidic gases. Of the failures not attributed to corrosion, those occurring due to erosion or fluid cutting adjacent to orifices in tubing, couplings and gas-lift valves were most prominent. The 301 failures from all causes were repaired at a cost of some \$2,342,000, or an average of \$7800 each. Repair of the 238 failures due to corrosion cost \$1,097,014, or approximately \$4600 each. As a result of this study, it was apparent that certain corrosion preventive measures had apparently prevented failures or minimized losses in many fields. These measures in-

cluded appropriately planned mud and cementing programs, the use of inhibitors for protecting the inside of casing and the use of insulating flanges or unions to minimize the flow of electrical currents.

It has been observed by one operator that very few casing failures have been encountered in those fields in which highly alkaline muds were used in the drilling and running of casing strings and this observation is believed of particular significance.

Causative Factors

The failures of oil string casing are usually attributed to one or more of the following causes:

External Corrosion Causes

1. Bacterial attack
2. Contact with formations of varying mineral and fluid content
3. Electrolysis caused by stray and subsurface electrical currents
4. Galvanic action caused by the presence of dissimilar metals in close proximity
5. Metallurgical defects in casing.

Internal Corrosion Causes

1. Vapor space attack by acidic gases
2. Fluid zone attack by acid waters
3. Corrosive gas-lift gas
4. Atmospheric oxygen intrusion
5. Unspent acid from acidizing operations
6. Erosion by sand and fluid
7. Instrumentation damage.

Table II, showing the results of the aforementioned subcommittee survey, indicates stray currents and aggressive fresh waters to have been the most frequent cause of failure in the 123 cases reported, with acid gas vapor zone attack not far behind. More recent developments indicate bacterial corrosion may be a far more significant causative factor than originally thought. Hadley[3] was among the early pioneers in recognizing the significance of microbiological corrosion. His works, as well as those of Starkey and Wight[4] and Bastin et al,[5] provide a thorough discussion of the subject. In view of recent evidence in the Ventura Field of California, East Texas and the Colorado Field of South Texas, the significance of microbiological corrosion cannot be underestimated.

Preventive Measures

Preventive measures most commonly practiced at the present time are as follows:

1. The installation of insulating flanges at the wellhead
2. The use of protective coatings
3. The placement of highly alkaline muds at points of possible or known serious attack
4. The placement of gel-type materials of an inorganic or organic nature
5. The use of volatile or nonvolatile inhibitors where annulus seals by means of packers or fluid can be obtained
6. Intermittent oil coverage
7. The application of cathodic protection.

TABLE II—Cause of Failure

Reported Cause of Failure	Number	Percent
Stray current	37	30
Acid waters	37	30
Acidic gases	23	19
Bacterial attack	9	7
Salt water	5	4
Unknown	6	5
Other	6	5

Installation of insulating flanges to isolate the wellhead and subsurface equipment from the flow line to eliminate surface stray currents has been very effective in many fields. Hammond and Ewing[6] report a remarkable reduction in the number of failures at Loudon while another operator[7] reports reduction in casing failure frequency of 75 and 60 percent in the Talco and Tomball fields. This measure is less effective where soil resistivities are extremely low or electrolysis is the result of subsurface currents.

The use of protective coatings has been given little consideration because of the obvious difficulties of application to pipe in place and the possibility of mechanical damage to the coating when installing new pipe. Evaluation would also present a difficult problem.

Placement of highly alkaline drilling fluids or gel-type materials has been reported in a number of fields. One operator reports the pumping of highly alkaline "red" mud into the annulus of a number of wells in the East Texas Field. This measure will be discussed at length below. This presents problems however, involving

1) possible collapse of casing since the condition of the casing is unknown, and
2) the movement of the displaced or injected fluid to the proper location.

Another operator reports laboratory investigations to indicate that the organic gel-type materials commercially available at present provide an excellent culture medium for bacterial growth.

Setting packers and loading the annulus with alkaline fresh-water muds or nonvolatile inhibitors in crude oil is one of the most widely practiced measures to eliminate internal vapor or fluid zone attack from acid gases and waters. It is obviously an effective and fairly positive solution to the internal corrosion problem as long as packers may remain in the well. The intermittent or continuous lubrication of such inhibitors into the annulus of pumping wells is also widely practiced and effective. The use of volatile inhibitors such as anhydrous ammonia in the annulus of wells having fluid seals shows promise but details of lubrication need to be worked out.

The use of cathodic protection to control external attack is receiving intense study by a number of operators at the present time. One operator reports its application by the use of magnesium anodes to some 225 wells in one field in the West Texas area and several operators are experimenting with it in the East Texas Field. There is considerable question as to the maximum depth to which such measures are effective since the operator has little control over variable formation resistivities. However, one operator has reported results to indicate cathodic protection can be obtained to a depth of 6500 feet at current densities of 0.03 milliampere per square foot. Either rectifiers or galvanic anodes may be used as the source of direct current.

The casing potential log has been used by a number of operators to study surface and subsurface

currents in wells and to investigate the effect of the application of cathodic protection at the wellhead. The logs presently used are of the single and multiple electrode types. The former consists of a single electrode run on a standard electric logging cable. This instrument gives a continuous log of casing potential with respect to wellhead potential or, as more commonly used, readings may be made at intervals and the data plotted for interpretation. The latter or multiple electrode method involves the measurement of potential difference between two electrodes at fixed distances apart. Current practice with this instrument also involves the use of interval readings. Readings may be obtained with the flow line connected or disconnected in order to observe the effect of surface and subsurface currents. While the relative merits of the two types of instruments is a matter of considerable debate both obtain results which, when properly interpreted, are believed of considerable value in the study of the application of cathodic protection to casing strings.

Problem Areas

Committee studies have indicated five general geographic areas where casing corrosion is a matter of more than general concern. They are as follows:

Area	Surface Attacked	Causative Agent
East Texas	External	Corrosive fresh water and bacterial attack
West Texas-New Mexico	Internal	Vapor zone attacked by acidic gases
Magnolia, Arkansas	Internal	Vapor zone attacked by acidic gases
Kansas	External	Contact with Dakota water sand
California	External	Bacterial attack

Each of these areas presents a problem serious in magnitude. The West Texas-New Mexico and the Magnolia, Arkansas, areas present very similar problems involving sour crudes, while the other three areas present widely different characteristics.

East Texas Area

A recent survey in the East Texas Field showed 80 percent of all casing failures on which the depths of failure were known occurred above 400 feet and 62 percent between 200 and 325 feet. The most serious corrosive attack occurs over an interval of 50 to 75 feet. Although there is some disagreement among the operators as to the most significant causative factor, a corrosive fresh water sand is known to exist over the major portion of the field at a depth of 150 to 300 feet. This water contains approximately 100 parts per million total solids, relatively high iron and carbon dioxide contents and has a pH value of 5 to 6 immediately after being produced at the surface. A representative analysis of the water is presented in Table III.

TABLE III

Analysis of Water from Ida Hall "B" Lease Water Well
East Texas Field—Rusk County—Depth 140-180 Ft.

Constituents	Parts Per Million	Constituents	Parts Per Million
Sodium	43	Bicarbonate	18
Calcium	13	Total Solids	190
Magnesium	8	Iron	3
Chloride	88	Hardness	66
Sulphate	20		

pH = 5.9

In addition, a ferrous sulfide slime has been observed on the affected areas of failed pipe, indicating bacterial action. Flow line current surveys and casing potential logs have not been conclusive as to the presence or absence of surface and subsurface currents. In general, it is believed an attempt to fix a single causative factor would result in oversimplification. It is quite likely that all three factors are involved.

Repair has involved setting packers, squeeze cementing, cutting and pulling the casing and replacing it by the use of the casing bowl and the running of inside liners where casing size limitations permitted.

On the assumption that the corrosion can be arrested by isolation of the casing from contact with the corrosive fresh waters, one operator has placed highly alkaline mud behind the casing in five wells to a depth below the zone where the leaks normally occur. This should also prevent bacterial attack. To evaluate the effectiveness of this method of control, the wells were selected in areas where numerous casing leaks have occurred and when two are abandoned in the near future, the casing will be recovered and inspected. The principal operational problem observed in the placement of mud in the wells has been the difficulty experienced in pumping it to a depth sufficient to provide protection from corrosion throughout the interval susceptible to casing leaks. A small rotary pump capable of pumping against a head of 150 pounds per square inch was used to pump the mud behind the casing, displacing the existing well fluids to the formation. In those instances in which this pressure was insufficient to pump the mud behind the casing, a tubing packer was set in the well and a balance pressure applied to prevent collapse of the casing as the mud was placed with a reciprocating pump. While sufficient pressure could be obtained in this manner, loss of mud to shallow formations prevented it from reaching the desired depth on two jobs. Jelflake was used in an attempt to prevent this loss of mud but it was not completely effective. On future jobs it is planned that other lost circulation materials will be tested. This operator has estimated that at least 750, or approximately 25 percent, of its wells will develop casing leaks before the reservoir is depleted. To repair this number of casing leaks using patch tools —the most satisfactory method at present—would cost approximately $3,225,000. Treating the wells by placing the highly alkaline mud behind the casing can be accomplished at a cost of $200 per well so, even if it is necessary to treat as many as 1500 wells to insure full coverage of the area where casing leaks are most likely, the total cost would be only $300,000. Procedure used on five jobs performed to date included tracing the mud as it is pumped behind the casing with a radioactive tracer and gamma ray logging instrument. Consequently, the cost of these

experimental jobs has been higher than future jobs. The first five jobs cost approximately $700 per well.

Cathodic protection is receiving serious consideration by a number of operators in the area as a possible preventive measure. Initial installations are now being made and will be watched with interest.

West Texas-New Mexico

Casing failures became so widespread in the West Texas-New Mexico areas in recent years that both the production operator and state regulatory bodies have become quite concerned. Investigations disclosed that casing failures were widespread in the Wasson, Slaughter, Seminole, Levelland, Means, Hobbs and Adair fields. Production of many wells in these fields is limited by capacity, so any downtime results in loss of oil. One company estimated, on the basis of repair and workover experience, that in excess of $5,000,000 would be spent on its wells alone if no preventive measures were adopted. Cooperative study by the producing companies eliminated galvanic action as the major cause of failure. Correlation of external pit depth versus casing potential logs indicated excellent agreement in that most subsurface currents were shown to leave the casing immediately below the surface string setting but no case of complete perforation in those areas was observed. In fact, the majority of casing strings which have been pulled have shown little evidence of external attack. With the possible exception of one field in the area no evidence of bacterial attack has been observed. Casing caliper surveys and visual inspection of pipe recovered have demonstrated that predominantly all attack is confined to the vapor space of the wells. It is thought that corrosion results from condensation of moisture on the cool wall of the casing opposite water sands in the presence of the acidic gases, carbon dioxide and hydrogen sulfide. The acidity of the condensed water is believed a function of the acid gas concentrations and the total pressure in the annular space. Several major operators are attempting to correlate acid gas pressure history and corrosion damage in wells in this area. Preliminary work has been encouraging and possibly a suitable basis for specification of a corrosion preventive program may result.

The most widely accepted program of prevention at the present time involves the setting of tubing packers and the loading of the annulus with water-free crude oil containing one to two gallons of inhibitor per 100 barrels of oil. A second method which shows promise is the lubrication of volatile inhibitors such as anhydrous or aqueous ammonia into the annulus of those wells in which there is a fluid seal. One operator has reported the presence of ammonia vapor in the annular space up to nine months after a batch lubrication of the chemical.

TABLE IV—Methods of Repair

	Number	Percent
Squeeze cement	73	60
Tubing packer	10	8
Inside liner	15	12
Casing patch	19	15
Unreported	6	5

The continuous and intermittent lubrication of adsorptive- and wetting-type inhibitors is practiced by some operators in pumping and gas-lift wells. This method has the advantage of providing protection to both the casing and the tubing but there is no ready means of determining the degree of protection obtained by this or the volatile inhibitor other than failure records, a slow and time-consuming method.

Repair of failures is accomplished by one of three methods:

1) squeezing the leak with cement or plastic.
2) setting an inner string of smaller diameter pipe, or
3) cutting and pulling the corroded section of casing and rerunning a new section and attaching to the old string by means of a casing bowl or patch.

The first is the most generally practiced procedure, although due to the poor condition of the pipe, additional holes may be created by the application of pressure. The setting of an inside string of casing is often impossible in many wells because it was originally cased with 5½-inch pipe, the smallest practical size in which normal production operations can be obtained. The third method is somewhat hazardous because of the original abnormal well bore enlargement through the thick salt section prevalent in the Permian Basin area. In many instances no allowances were made for this enlargement in the original calculations of cement requirements for setting intermediate and oil strings; consequently, many of these strings remain in place under varying degrees of tension and compression without horizontal support through much of the salt section. Casing failure occurring in the enlarged bore through this section, resulting in complete severance of the casing, may result in complete misalignment of the free end of the pipe when the tubing is pulled. In this event, abandonment of the well or redrilling, if economics permits, is indicated. Normally, however, repair is accomplished by the setting of inner strings and cementing to the surface.

The average cost of setting a packer in wells in the area is $1000, while cost of repair of a casing failure averages $25,000 unless complications arise.

Magnolia, Arkansas

Casing failures in the Magnolia, Arkansas, sour crude area are very similar to those in the West Texas-New Mexico area and have been thoroughly discussed by Bailey and Crowell.

Kansas-Illinois

In the Kansas and Illinois area, casing failures have been abnormally high under two particular conditions. Numerous failures have occurred, as in the West Texas-New Mexico area, from internal attack of acid gas in the vapor zone in the Bemis-Shutts and Iuki-Carmi fields of Kansas. Even a greater number of failures have occurred at rather shallow depths as a result of external attack of casing by aggressive waters in the Dakota sand section in the Trapp, Dorr, Kreuger and Morel fields. These fail-

ures are usually repaired by squeezing cement at an average cost of $3000.

California

Doig and Wachter[9] have fully described failures in the Ventura Field of California, and, after extensive investigation and elimination of other causative factors, attribute failure to bacterial corrosion. Certain species of bacteria, presumably of the sulfate-reducing variety, have been isolated in the corrosion products in contact with the casing. Since highly alkaline environments are known to stifle bacterial activity, the use of highly alkaline muds in the drilling of all new wells was adopted as standard practice to prevent future failures. This does not provide a solution to the prevention of bacterial corrosion in existing wells, however.

Other Areas

One operator has recently reported an abnormal number of casing failures in the Colorado Field of Jim Hogg County in the lower Texas-Gulf Coast area, which is believed to add additional significance to the importance of microbiological corrosion. This field was discovered in 1939 and produces from the Cockfield sand at a depth of approximately 3200 feet. It is a solution gas-drive sand and produces a sweet crude of 46 degrees API gravity with little or no salt water. This particular company operates 118 pumping wells in the field and a pilot water flood project has been initiated in the southern portion of the field.

Most of the wells in the field were completed at the time when steel was very short, but the following is a typical casing program: 10¾-inch 32.75-pound first-class lapweld casing set at 112 feet with 75 sacks of cement; 5½-inch 14-pound first-class lapweld casing set at 3070 feet with 125 sacks.

To date nine casing failures have occurred at depths of 1450 to 1550 feet, leading one to suspect that the lapwelds were opening up. Flow line current surveys and casing potential logs ruled out the possibility of surface or subsurface currents.

On recent abandonment of one of the wells, an attempt was made to recover the casing to a depth of 1600 feet for examination. Unfortunately, only 1128 feet (28 joints) was recovered, the top 1050 feet of which was pulled dry. The casing was in essentially new condition internally. Externally, except for the first four joints, it was covered with an almost dry ¼-inch thick cake of greenish-black slime in which ferrous sulfide was present and the presence of sulfate-reducing bacteria was confirmed by laboratory examination. Removal of the slime revealed corrosion damage of an unusual nature in that attack appeared to be linear in character as revealed in Figure 1. Subsequent laboratory examination ruled out the possibility of attack along the lapweld since this particular pipe proved to be seamless. The severity of attack appeared to increase with depth and about three to five feet from the pin end attack took the form of circumferential bands approximately one inch apart as shown in Figure 2. On the basis of these facts, these failures have been

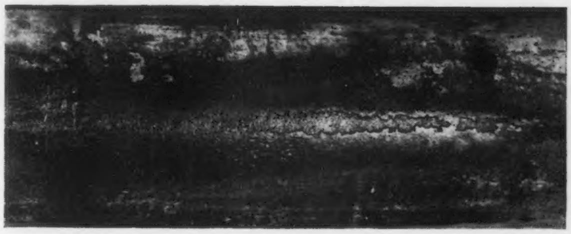

Figure 1

Figure 2

attributed to bacterial attack. This operator anticipates experimental work on the injection of highly alkaline fluids between the surface string and oil string annulus.

Repair Procedures

Repair procedures have been discussed in connection with areal problems; however, a brief explanation of these techniques is believed desirable. The most commonly practiced procedures are:

1. The setting of a tubing packer
2. The setting of an inside liner
3. The placement of cement by squeezing
4. The cutting and removal of damaged casing and replacement by means of casing bowl assembly.

The setting of a tubing packer below the point of leakage in the casing is the most economical method of correcting a casing failure. Unless complications arise, it can normally be accomplished for $1000 per well or less. However, this generally is considered the least satisfactory method except for temporary repair. The point of failure is not sealed and corrosive fluids are admitted to the annulus to attack the tubing and packer element which frequently leaks and admits the formation fluids to the producing well bore. This method is seldom approved by state regulatory bodies.

Setting of an inside liner to total depth is practiced in certain areas where original casing size will permit. Unfortunately, 5½-inch casing was set in many wells as the production string, which obviously does not allow the later setting of an inner string of practical size. The setting of 4½-inch flush joint liner in such casing is the smallest size available through which normal production operations as now practiced may be conducted. The cost of run-

ning an inside liner varies, of course, with depth and availability of steel but may cost anywhere from $5000 to $35,000. More recently the setting of partial liner strings has been practiced to seal leaks but the cost of such operations frequently approaches the cost of setting a liner to total depth.

Cementing a casing leak by squeeze methods merely involves the placement of cement at the point of failure by a method which restricts its application to a certain portion of the formation and, by the application of pressure, the cement is driven into the point of failure and into the formation. Thus, the failed portion of casing is surrounded by a sheath of cement. This is the most frequently used and successful method of repair and is usually accomplished at a cost of $3500 to $7500, depending upon the number of stages required to obtain a shut-off.

Replacement of damaged casing with new pipe using the casing bowl or patch tool assembly involves setting a plug below the point of failure, mechanical cutting of the casing below the point of damage, its recovery and the rerunning of new pipe with the patch tool designed to locate and slip over the remaining portion of the casing in the hole. A seal between the new and old casing members is made by means of casing slip and pack-off element, which leaves the casing without internal obstruction for future production operations. This method is preferred by some operators though slightly more expensive than squeeze cementing because a more positive repair is obtained. This is the only method which permits recovery of the corroded casing for visual examination. The cost of such a repair again varies with the depth of the leak but currently repairs are being made in the East Texas Field by several operators at costs of $3750 to $4300, exclusive of the pipe used.

Suggested Procedures to Prevent Failures

Certainly, casing corrosion must be examined from the standpoint of well control and safety with due consideration for the economics involved. Every effort should be made to detect casing leaks early in the life of a field and to adopt corrective or preventive measures before existing metal is lost. For the benefit of the practicing corrosion engineer who is confronted with the problem of casing corrosion, the following suggestions are offered.

1. Evaluate the corrosive characteristics of new fields early in the life of the field in order that suitable mud and cementing programs, from a corrosion standpoint, can be adopted.
2. Install insulating flanges in the flow lines of all new wells completed as producers unless previous surveys in that field have indicated such flanges are unnecessary.
3. Install insulating flanges in all wells in old fields in which flow line current surveys and the remaining reserves of the field indicate such action would be economical.
4. If casing is recovered from areas where corrosion failures have occurred, have a qualified corrosion engineer present to examine the casing at the well site immediately following its recovery from the well bore.
5. Make full use of volatile and nonvolatile inhibitors in wells known to be corrosive.
6. Examine all recovered subsurface equipment thoroughly for corrosion and maintain complete description and cost data on damaged equipment.
7. Eliminate the use of perforated tubing, couplings and orifice buttons as a means of protection in every instance possible. Consideration should be given to the incorporation of reverse check valves in all gas-lift valves.

Conclusions

The seriousness of the problem of corrosion of production string casing in oil and gas wells has only recently been recognized. The causes of corrosion failure can be recognized in most cases by a thorough study of the environmental factors. Adequate "tools" are available for studying the casing corrosion problem except for the lack of a proved device for determining the condition of the outside of the casing in place. Certain corrosion preventive measures apparently have minimized losses in many fields. These measures include appropriately planned mud and cementing programs, the use of inhibitors for protecting the inside of casing and the use of insulating flanges to minimize the flow of surface electric currents. Obviously, much work remains to be done in the application of cathodic protection and the placement of highly alkaline fluids as preventive measures.

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Casing Corrosion in West Texas-New Mexico ★

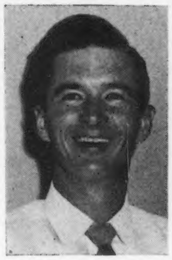
By R. L. ELKINS

Nature of Problem

INTERNAL casing corrosion in the upper gas-filled portion of the tubing-casing annulus was first noted by the Shell Oil Company in the West Texas-New Mexico area in December, 1945. The first casing failure resulting from this cause was discovered when in the course of workover operations in a Hobbs Field well severe corrosion was found on the exterior of the tubing string. Further investigation revealed internal casing corrosion and failures. A survey of the company's remaining 26 wells in the field revealed casing failures in three other wells. Although surveys were conducted in the Wasson Field shortly after the discovery of this problem in the Hobbs Field, no casing corrosion damage was noted. Three years later, however, it was discovered that severe corrosion of this type was occurring in the Wasson Field, indicating that the earlier surveys had either been conducted before casing damage was appreciable or the detection methods used were inadequate. Since 1948, when internal casing corrosion was found in the Wasson Field, this type of corrosion has been detected in many other fields in the West Texas-New Mexico area. Fields in which such corrosion has been found include Hobbs, Wasson, Eunice, Monument, Slaughter, Monahans, and Goldsmith.

Corrosion failures of oil well casing in these fields have in nearly every case presented troublesome and expensive problems. The casing corrosion problem in the Wasson Field illustrates its nature and severity. Based on data from operations in the field, it is estimated that casing failures have occurred in approximately seventy of the 1700 wells during fifteen years after 1938 when development of the field began, to 1953. Casing repair operations have cost from $3000 to $40,000 per well, probably averaging $20,000 each. Thus, the minimum losses resulting from casing failures in the Wasson Field amount to about $1,400,000 or the cost of casing repairs. If corrosion is not controlled, this expense will be considerably greater during the remaining 30 to 40-year estimated field life, because the frequency of casing failures is rapidly increasing. A graph (Figure 1) showing the increasing frequency of casing failures in Shell's Wasson Field wells before control measures were applied, illustrates this point.

Large losses were incurred as a result of some casing failures when attempted repair operations were unsuccessful and the wells were abandoned and redrilled. In other cases gas and oil escaped through casing failures into a shallow "thief" formation and resulted in lost reserves and dissipated reservoir energy. This escaping gas also pressured the shallow formation and caused hazardous drilling in the area. At least one known "blow-out" resulted from this in a well being drilled.



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Abstract

Internal casing corrosion in the upper gas-filled portion of the tubing-casing annulus is a costly and widespread problem in the West Texas-New Mexico area. Severity of the problem is illustrated by experiences in the Wasson Field where an estimated $1,400,000 was spent in casing repairs during the first fifteen years after development of the field and other large losses occurred which could not be estimated. This problem also has been detected in at least six other large fields in the area.

It is believed that corrosion results from the condensation of moisture on the casing interior and subsequent absorption of acid gases. All findings to date substantiate this theory.

Corrosion of this type is being controlled by packing off and filling the tubing-casing annulus with a noncorrosive fluid, thereby excluding the corrosive gases and protecting the casing from future failures. Application of this protective measure costs about $1200 per well as compared to the $3000 to $40,000 expenditure for repair operations in the event of a casing failure. Other promising protective measures, which would be more easily applied and less costly if effective, are currently being tested.

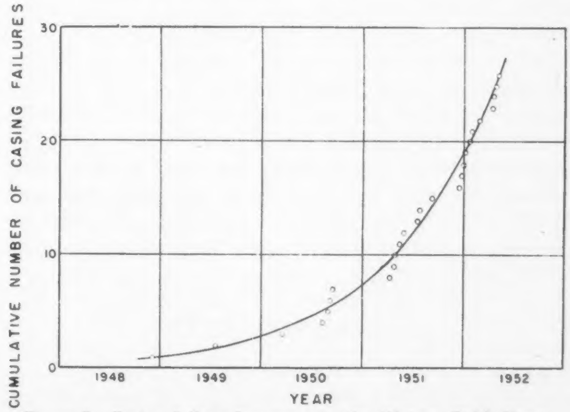

Figure 1—Casing failure frequency in the Wasson Field, Texas.

★A discussion supplementing the information in the paper Corrosion of Casing in Oil and Gas Wells by Jack L. Battle and like it presented at the Ninth Annual Conference, National Association of Corrosion Engineers, Chicago, Ill., March 16-20, 1953.

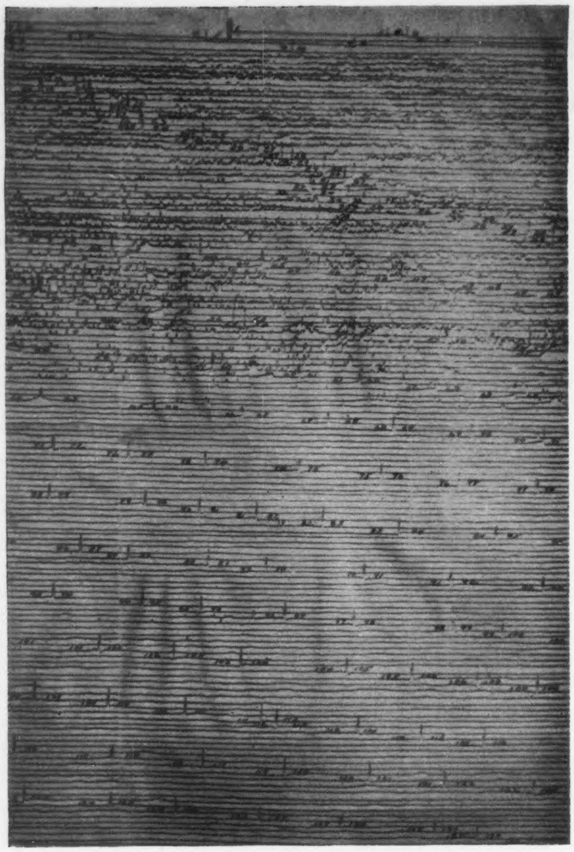

Figure 2—Casing caliper survey of a Wasson Field well.

Even though casing corrosion problems in the other fields mentioned apparently are less severe than that in the Wasson Field, economic losses in these fields nevertheless have been appreciable.

Casing Repair Methods

Repair of casing failures has been effected by

1) running and cementing an inner string of casing,
2) pulling and replacing the corroded portion of casing string, or
3) squeeze cementing.

Of these, the first method probably made the cheapest and most lasting repair. In 5000-foot Wasson Field wells, casing repairs by this method have cost an average of about $11,000 each when second hand casing was used. Principal disadvantage of this type of repair has been the resulting reduction in casing string diameter which limits the size of the tubing string that can be installed in the well. In cases where wells were completed initially with small diameter casing strings this disadvantage alone has ruled out its use.

Casing repair by the replacement method generally has been the most expensive of the three methods. Its high cost has resulted primarily from workover rig time consumed in cutting off the corroded portion of casing string and removing it by sections. Many difficulties were encountered in this operation, such as caving formations, stuck casing and casing "fishing" jobs. The average cost of replacing the upper 2500 feet of casing in Wasson Field wells by this method has been about $30,000 each. It does have the advantages of providing a lasting repair and maintaining the original diameter of the casing string and because of this latter advantage it has been used in repairing numerous wells equipped with small diameter casing strings.

Casing repair by squeeze cementing usually has been less expensive than the replacement method, costing an average of about $12,000 each. This method possesses several bad features, though. Namely, when this repair method is used the severely corroded casing is left in the hole and provides numerous weak points where additional casing failures might develop. It is doubted, too, that the squeeze cement repairs will hold until well depletion in large reserve and long producing wells such as those in the Wasson Field. In addition, attempted repairs by this method occasionally have collapsed corroded well casing and necessitated redrilling the well.

Corrosion Detection Methods

Internal casing corrosion has been detected by such methods as calipering the casing interior, visually examining pulled casing strings, pressure testing, analyzing casing gas, visually examining tubing strings and checking for gas or oil pressure around the outside of the casing. The casing caliper survey probably has been the most useful detection method because of its relative low cost, ease of application and abundance of information. Numerous surveys of this type have been made in the fields experiencing internal casing corrosion. A caliper survey (Figure 2) made of a casing string in the Wasson Field illustrates the amount of information provided regarding the severe corrosion found in the upper, gas-filled portion of the string.

Visual examination of pulled casing has been a second method of obtaining information. However, this method generally is possible only when a well is to be abandoned or the casing repaired by the replacement method. Examinations of casing pulled from the Wasson and Monument Fields revealed severe localized corrosion pitting as illustrated in Figures 3 and 4.

Analyses of casing gas have been used quite often as a method of predicting the possible occurrence of internal casing corrosion. This method is extremely low in cost and easily applied but it provides only an indication that corrosion may or may not be occurring. Analyses of casing gas in many of the fields experiencing internal casing corrosion revealed concentrations of acid gases (hydrogen sulfide and carbon dioxide) in the order of 2 to 8 percent. Partial pressures of these gases in the casing ranged from 30 to 100 psi. In the Wasson Field the gas is composed of approximately 7 percent carbon dioxide and 0.1 percent hydrogen sulfide. In the Monument and Eunice Fields these concentrations are about 4.5 percent carbon dioxide and 1.5 percent hydrogen sulfide.

Visual examination of tubing strings has provided another source of information regarding internal casing corrosion. However, tubing examinations have been very misleading when this detection method alone was used. Examinations of numerous tubing strings pulled in the Wasson, Monument and Eunice Fields revealed that external tubing corrosion occurred in only a few cases. In many cases where the casing in a well was badly corroded the tubing was in excellent condition. In the few cases where corrosion damage was found on a tubing string, this damage was very localized, occurring on the exterior of only a few collars and tubing upsets. The corrosion on the tubing upsets was usually in the form of a ring located just beneath the top edge of the collar. A photograph (Figure 5) of tubing pulled from a Wasson Field well illustrates the nature of this attack.

Mechanisms of Corrosion

It is believed that corrosion in the gas-filled portion of the casing results from the condensation of water on the steel surfaces and subsequent absorption of carbon dioxide and hydrogen sulfide gases to form an acid solution. The water vapor condenses on the inside of the casing in the upper portion of the casing string because the upper formations in contact with the casing are cooler than the lower formations where the water vaporized. Enough water is condensed in many of these wells to cause corrosion even though they produced 1 percent or less water. Laboratory analyses of corrosion product taken from

TABLE I

Component	Percent (Weight)
FeS	44
$FeCO_3$	37
FeS_2	2
$FeSO_4$	5
Fe Acetate	3
Inorganic contaminants	9
	100%

a casing string in the Wasson Field showed that this product consisted of 37 percent iron carbonate and 44 percent iron sulfide (Table I). These data substantiate the postulated corrosion mechanism. A small amount of organic acidity was also found, indicating the possibility that volatile organic acids, may have participated in the corrosion reaction. The small amount of free sulfur and sulfate ions found probably resulted from oxidation during sampling and therefore may not be indicative of any oxygen effect in the original corrosion reaction.

In this type of corrosive environment tubing oftentimes suffers little or no external corrosion in wells which experience severe internal casing corrosion, even though both of these surfaces are exposed to the same gas. It is believed this is due to differences in conditions on the tubing exterior and casing interior. First, tubing strings are often thoroughly coated on the exterior with grease and oil, which could form a protective film. Second, tubing temperatures are generally higher than casing temperatures because the produced fluids flow through the tubing and warm it. This difference in tubing and casing temperatures favors condensation of water on the cooler casing surfaces.

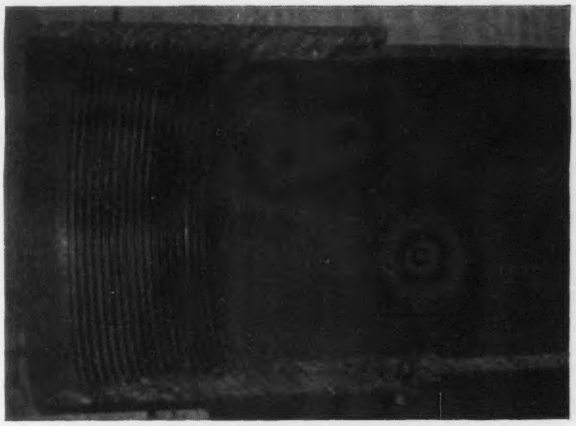

Figure 3—Internal casing corrosion in a collar.

Figure 4—Internal casing corrosion in the pipe body.

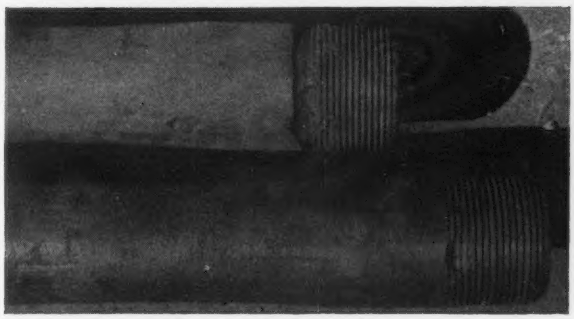

Figure 5—External corrosion of tubing.

External tubing corrosion found on occasion probably resulted from mechanical contact between the tubing and casing which allowed condensed water from the casing to wet the tubing. Tubing collars corroded on one side only, are further evidence supporting this belief. Condensed water from the casing probably collected around the top edge of some of the tubing collars and caused the ring type corrosion damage illustrated in Figure 5.

Corrosion Control Methods

The commonly used and only proved method of combatting internal corrosion of the gas-filled portion of casing strings has been to pack off the tubing-

casing annulus just above the producing formation and fill this annulus with a noncorrosive fluid, which in most cases has been inhibited crude oil or mud. In this manner the corrosive acid gases are excluded from the casing. Some corrosive wells in the West Texas-New Mexico area have been packed off and protected in this manner for the past seven years and have experienced no further corrosion damage. Experiences in the Wasson Field, where the cost of this control method has averaged about $1200 per well, illustrate the economics of this method. Here the corrosion control cost is only 6 percent of the cost of repairing a typical casing failure. Shell Oil Company recently completed a program in the Wasson Field whereby nearly all of their wells were protected in this manner and it was estimated that the program would save $2,000,000 to $3,000,000 in the cost of casing repairs alone during the remaining 30 to 40-year life of the field. If all factors, such as lost reserves, dissipated reservoir energy and unsuccessful repair operations could have been evaluated, the program would have shown substantially greater savings.

Other promising control methods are being tested currently but sufficient data have not yet been collected to determine their effectiveness or economics. Two of these control methods, inhibiting the casing gas with volatile inhibitors (ammonia) and periodically wetting the interior of the casing by flushing with inhibited crude oil, are much more easily applied than the pack-off method and probably will be much less costly if they prove effective. Obviously, there is a great need for such inexpensive and easily applied control measures as these, because the annulus pack-off control method is relatively expensive and necessitates "killing" the well and its use therefore is often limited to the better wells. However, if either of the methods under test prove effective it could conceivably be used in both long producing and marginal producing wells.

Acknowledgment

The author thanks Shell Oil Company for permission to publish this article and acknowledges the assistance of R. P. Moscrip, Midland, Texas and the contributions to this portion of the company corrosion efforts by T. S. Zajac, New York, N. Y., J. L. Ward, R. L. Warden and the Corrosion Department of the Shell Development Company.

Cable System Design For Cathodic Protection Rectifiers★

*By RAY M. WAINWRIGHT**

Abstract

The design of any current-carrying cable system involves certain basic factors, which may be listed briefly as follows:
1. Ability to meet mechanical stresses and other environmental requirements; 2. Ability to meet voltage attenuation limits; 3. Ability of the insulation to withstand applied voltages; 4. Ability to meet limitations on current due to temperature and insulation stability; 5. Conformance to Kelvin's Economic Law; 6. Conformance to legal codes, safety rules, and similar requirements.

The importance of each of these factors is discussed in the light of cathodic protection requirements and installations. Emphasis is placed on cable systems which connect the direct current output terminals of the rectifier to ground beds and to the protected metal structures.

Frequently engineers disregard one or more of the six factors in designing cathodic protection cable connections. For example, the tendency is to design to fit the current-carrying capacity of cables as set forth in the various handbooks and to neglect a consideration of Kelvin's Law, which shows that the choice should be toward much larger cables and lower current densities. Also because cables buried underground are subject to concentrated electrochemical attack the type of insulation is important. Ordinary insulations may not be sufficient and normal voltage ratings may be unimportant.

A method of determining annual fixed costs of cables is outlined and charts are given which enable the engineer to balance fixed charges against cost of losses and thus select the optimum cable size based on economy. Consideration also is given to the effect on the economic picture of selecting cable sizes somewhat off of the theoretical optimum.

THE PROBLEM of designing current-carrying conductors between cathodic protection rectifiers and ground beds or underground structures is one which has received too little attention in the past among corrosion engineers. This article attempts to outline the considerations involved and to point out, in particular, the economic implications of cable design.

Basic factors of design are:

1. Ability to meet mechanical stresses and other environmental requirements.
2. Ability to meet voltage attenuation limits.
3. Ability of the insulation to withstand applied voltages.
4. Ability to meet limitations on current due to temperature and insulation stability.
5. Conformance to Kelvin's Economic Law.
6. Conformance to legal codes, safety rules, and similar requirements.

These factors are taken up separately to show the relative importance of each.

1. *Mechanical Stresses and Environmental Requirements*

Most electric transmission line handbooks list mechanical stress tables for cable spans, showing the length of span permissible under various clearance requirements, materials, wind pressure, ice loading and similar factors. For the purposes of this article it will be assumed that the overhead lines will be checked for sag and stress prior to construction and that the final choice of material or of size will not depend upon mechanical requirements. Thus only for very long spans would it be necessary to go to steel reinforcing or special material specifications.

Normally overhead lines of the low voltage dc types are designed using bare copper cable, although in some cases codes and other considerations will dictate weatherproof wire, aluminum, or other conductor materials. For underground lines, neoprene or neoprene and rubber combinations currently are favored as insulation material. The problem is one of chemical stability over long periods of time exposed to moisture and soils and the maintenance of good insulating characteristics indefinitely. Mechanical stresses of underground cables are usually unimportant.

On positive underground cables (attached to + terminal of rectifier), all splices and underground terminals must be very carefully insulated and must be absolutely water-tight. The smallest pinhole in the insulation will create an anodic area on the cable with resulting rapid corrosion of the cable metal. Even asphaltic compounds or tars have been found inadequate unless carefully applied. In order to prevent subsequent corrosion it also is essential to obtain a bond between the tarry compounds and the sheath material of the cable. The use of the newer pressure sensitive tape material shows promise for this application.

The insulation of splices and terminals on the negative underground cable runs theoretically may be of poorer quality, because they will receive cathodic protection. However, since the cables will be near the ground bed, the voltage will be high with respect to the surrounding soil and the resulting leakage current appreciable. In low resistance soils this writer has noted leakage currents of this type up to 25 percent or more of rectifier output and he believes that in general the negative cables should receive approximately the same insulation treatment as do the positive cables.

★A paper delivered at the Ninth Annual Conference, National Association of Corrosion Engineers, Chicago, Ill., March 16-20, 1953.
*Department of Electrical Engineering, University of Ilinois, Urbana.

TABLE I—M Factors

Cost of losses in 100 feet of copper cable at one cent per kwhr.

CABLE SIZE	CURRENT IN AMPERES 10	20	30	40	50	60	70	80	90	100
10	0.893	3.57	8.04							
8	0.561	2.25	5.05	9.00	14.00					
6	0.360	1.44	3.24	5.76	9.00	13.00	17.64			
4	0.226	0.905	2.03	3.62	5.65	8.14	11.08	14.46	18.30	22.60
2	0.1424	0.570	1.28	2.28	3.56	5.13	6.98	9.11	11.54	14.24
1	0.113	0.451	1.02	1.81	2.82	4.06	5.54	7.24	9.15	11.30
1/0	0.0893	0.357	0.804	1.425	2.23	3.21	4.47	5.71	7.23	8.93
2/0	0.0710	0.284	0.639	1.135	1.77	2.56	3.48	4.55	5.75	7.10
3/0	0.0562	0.257	0.506	0.900	1.40	2.03	2.76	3.60	4.55	5.62
4/0	0.0446	0.178	0.401	0.715	1.115	1.61	2.19	2.86	3.62	4.46
250 MCM	0.0378	0.151	0.340	0.605	0.945	1.36	1.85	2.42	3.06	3.78
300	0.0316	0.1265	0.284	0.506	0.790	1.14	1.55	2.02	2.56	3.16
350	0.0270	0.108	0.243	0.432	0.675	0.972	1.32	1.73	2.18	2.70
400	0.0237	0.0948	0.213	0.379	0.593	0.854	1.16	1.52	1.92	2.37
450	0.0201	0.0840	0.189	0.336	0.525	0.755	1.03	1.34	1.70	2.10
500	0.0189	0.0755	0.170	0.302	0.472	0.680	0.925	1.21	1.53	1.89
550	0.0172	0.0689	0.155	0.275	0.430	0.619	0.842	1.10	1.39	1.72
600	0.0158	0.0632	0.142	0.253	0.395	0.569	0.775	1.01	1.28	1.58
650	0.0145	0.0580	0.1305	0.232	0.362	0.522	0.710	0.928	1.17	1.45
700	0.0135	0.0540	0.1215	0.216	0.338	0.486	0.661	0.865	1.09	1.35
750	0.0126	0.0504	0.1132	0.202	0.315	0.454	0.616	0.805	1.02	1.26
1000	0.00945	0.0378	0.0970	0.151	0.236	0.340	0.463	0.605	0.765	0.945

TABLE II—C Factors

Equivalent annual cost of 100 feet of copper cable (15% of initial cost)

Cable Size	$0.30 Base Price Bare	W/P	Neoprene	$0.35 Base Price Bare	W/P	Neoprene	$0.40 Base Price Bare	W/P	Neoprene
10	0.163	0.189		0.186	0.212		0.220	0.235	0.857
8	0.262	0.282		0.300	0.322		0.339	0.361	1.42
6	0.415	0.429		0.475	0.490		0.537	0.551	0.93
4	0.656	0.671		0.753	0.768		0.850	0.865	2.63
2	1.10	1.08		1.25	1.23		1.41	1.38	3.66
1	1.38	1.32		1.57	1.52		1.77	1.71	4.80
1/0	1.74	1.62		1.97	1.87		2.22	2.11	5.30
2/0	2.18	2.04		2.48	2.34		2.80	2.65	6.53
3/0	2.74	2.56		3.13	2.96		3.52	3.34	7.85
4/0	3.44	3.23		3.93	3.72		4.42	4.21	9.83
250 MCM	4.11	3.82		4.69	4.40		5.26	4.98	12.90
300	4.92	4.58		5.61	5.27		6.30	5.97	
350	5.75	5.35		6.55	6.16		7.37	6.98	16.62
400	6.56	6.11		7.50	7.05		8.41	7.96	
500	8.20	7.65		9.35	8.80		10.50	9.95	22.16
600	9.83	9.16		11.20	10.55		12.60	11.94	
750	12.26	11.34		14.00	13.15		15.70	14.90	
1000	16.40	15.27		18.70	17.60		21.00	19.90	

TABLE III—Sample Work Sheet

	CABLE SIZE	V	F	T
L = **500** ft.	10	....	1.10	....
I = **40** amps.	8	75.00	1.69	76.69
P = **1** cents/kwhr.	6	48.00	2.68	50.68
Bare cable	4	30.20	4.25	34.45
(Rectifier Eff. 60%)	2	19.00	7.05	26.05
K_M = **8.33**	1	15.10	8.55	23.95
	1/0	11.85	11.10	22.95
K_C = **5**	2/0	9.40	14.00	23.40
	3/0	7.50	17.60	25.10
$V = M \times K_M$	4/0	5.95	22.10	28.05
	250 MCM	5.04	26.30	31.34
$F = C \times K_C$	300	4.21	31.50	35.71
	350	3.60	36.80	40.40
$T = V + F$	400	3.16	42.00	45.16
	450	....	....	....
	500	2.52	52.50	55.02
	550	....	....	....
	600	2.11	63.00	65.11
	650	....	....	....
	700	....	....	....
	750	1.68	78.50	80.18
	1000	1.26	105.00	106.26

Instructions on the Use of Tables I, II, III

1. Determine:
   a) Length of cable run, feet.
   b) Cost of power to rectifier in cents/kwhr.
   c) Rectifier efficiency in percent.
   d) Current to be carried by the cable, amperes.
2. Determine:

$$K_m = \frac{\text{(feet of cable)} \times \text{(cents/kwhr.)}}{\text{(percent efficiency of rectifier)}}$$

$$K_c = \frac{\text{(feet of cable)}}{100}$$

3. From Table I select the column of factors for the proper current. Multiply each M factor by K_m and enter in column "V."
4. From Table II select the column of C factors for the proper base price of copper and for the proper type of cable. Multiply each C factor by K_c and enter in column "F."
5. Add columns "V" and "F" and enter the sum in column "T." The minimum amount in column "T" will appear opposite the correct cable size.
6. Plot a bar graph of *T* versus *cable size* to determine graphically the variation of cost with size near the minimum cost point.

Note: The M and C factors of Tables I and II are in dollars.

2. Ability to Meet Voltage Attenuation Limits

Ability to meet voltage attenuation limits is not usually important in the design of rectifier output cables, unless the cables are uncommonly small in size. Enough voltage must be available to meet the circuit requirements and this will be a variable for each location. The problem of "low voltage" which may be disastrous to induction motors is of no particular consequence in cathodic protection work.

3. Ability to Withstand Voltages

The dielectric strength of cable insulation for cathodic protection application is also of small importance. Most cable insulations are good for at least 600 volts and such limits are far beyond those required in cathodic protection.

4. Ability to Meet Limitations on Current Due to Temperature and Insulation Stability

Unless the rectifier output cables are run indoors in conduit, the temperature of the conductors is not a problem, as a rule. Insulation stability can be, of course, important, but it should not be difficult in most installations to keep cable temperatures below the manufacturers' recommended levels. For most underground cables the watts loss per foot can usually be radiated to the surrounding soil with ample margin of safety.

5. Conformance to Kelvin's Law

Conformance to Kelvin's Economic Law is probably one of the governing factors in the design of rectifier cables for cathodic protection, hence considerable space and discussion will be given this factor.

The law states that: The proper size of cable is that for which the cost of losses equals the annual fixed charges. Another way of stating the law is: The proper cable size is one which makes the sum of the annual cost of losses and the annual fixed charges a minimum.

Annual cost of loses may be calculated from the relation:

$$V = \frac{0.0876\, I^2\, R\, P\, L}{E} \qquad (1$$

where, V is in dollars per year.
I is the current in amperes in the cable.
R is the resistance of 100 feet of cable.
P is the cost of power in cents/kwhr.
E is the efficiency of the rectifier in percent.
L is the length of cable in feet.

For computational purposes Equation (1 can be divided into two parts, or factors, thus

$$V = M\, K_m$$

$$\text{where } M = 0.0876\, I^2\, R, \text{ and } K_m = \frac{L\,P}{E}$$

Table I shows the M factors for various wire sizes and various conductor currents. These factors may be interpreted as the annual cost of losses, in dollars, of 100 feet of the cable in question, with power at 1 cent/kwhr. Then to obtain V, a K_m is computed based on the length of the cable, the cost of power and the rectifier efficiency. The rectifier efficiency is included since the power will be metered at the rectifier input and therefore the power to supply cable losses will be greater than the actual losses in the cable itself.

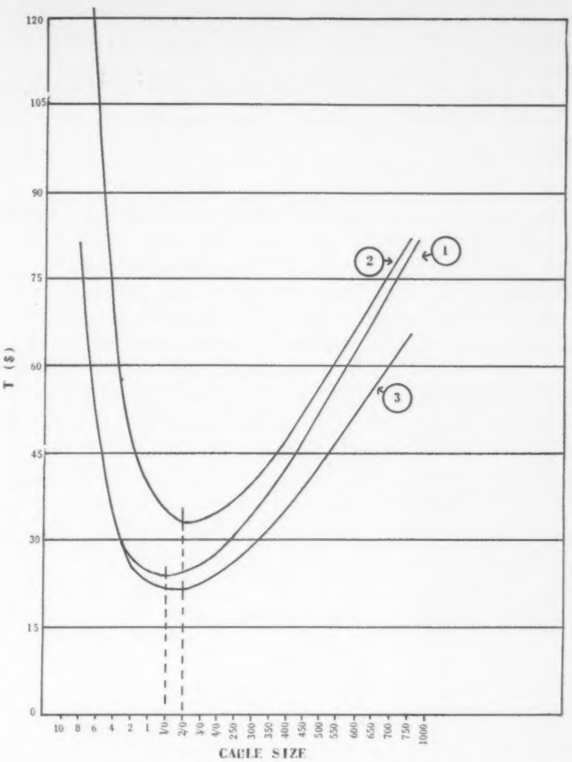

Figure 1—Cost versus size. Curve 1, 1 cent, 40 cents base. Curve 2, 2 cents, 40 cents base. Curve 3, 1 cent, 30 cents base.

Table III shows a column of V's for a particular example of 500 feet of bare copper cable carrying 40 amperes of direct current with power charged at 1 cent/kwhr.

The annual fixed charges of a cable may be computed by the relation:

$$F = 0.15\, S\, L \qquad (2$$

where F is in dollars of annual fixed charges.
S is initial cost of cable in dollars per foot.
L is length of cable in feet.

The factor 0.15 represents an estimate of annual charges as follows:

0.02 — depreciation
0.06 — interest
0.04 — taxes and insurance
0.03 — operation and maintenance.

Again for computational purposes, Equation (2 has been broken down into

$$F = C\, K_c$$

$$\text{where } C = 0.15\, S\, (100) \text{ and } K_c = L/100$$

In Table II the C factors have been plotted for various sizes and types of copper cables and give annual fixed charges for 100 feet of cable run. Table II shows C factors for bare, waterproof and a typical neoprene covered underground type of cable. Costs are average delivered at a location not over 500 miles from the wire mills. Bare and weatherproof are

shown for three different base prices of copper. The base price of copper for March, 1953, was approximately $0.40 per pound.

In Table III the cost factors F have been plotted for the previous example. The total cost, T, is then computed as

$$T = F + V \tag{3}$$

This cost is shown graphically as curve 1 in Figure I, with T plotted against wire size. The proper size of wire occurs at the point of least total cost. It is interesting to note that the proper size of cable may not be critical in the *neighborhood* of the proper size. Curve 2 shows the effect of increasing the power cost to 2 cents/kwhr, and curve 3 the effect of lowering the base price of copper to $0.30 per pound.

It should be noted that with rectifiers on REA lines where power costs may range up to 4 cents/kwhr or more to the company operating the cathodic protection system, the size of wire should be far greater than one's "intuition" would tell him, based on usual electrical wiring experience, or based on handbook values of current-carrying capacity. In fact if 1 cent/kwhr would indicate a 1/0 cable (for 500 feet and 40 amperes), 2 cents/kwhr would indicate 2/0, and 4 cents/kwhr would indicate 4/0.

Computations on the more heavily insulated wires, of course, show reduced sizes compared to bare cable for the same current and length, since fixed charges are a greater proportion of the total cost.

6. *Conformance to Legal and Safety Rules*

In most cases no particular warnings are necessary here. The corrosion engineer must install his cables to conform to minimum clearance requirements, restrictions on pole climbing space and so forth. In most cases he must also have easements to operate either overhead or underground cables across private property. Fortunately the low voltages normally encountered permit the cable runs to be classified legally as a ground wire and subject to the same restrictions on insulation and safety.

Some Notes on the Oxidation Resistance Of Boron-Containing Chromium-Nickel-Cobalt-Iron Alloys ★

By W. O. BINDER and E. D. WEISERT

DURING an investigation of a series of cast high temperature alloys containing boron it was noted that boron exerted an adverse effect on the oxidation resistance of some of the alloys considered. It became of interest to study the effect of base composition on the oxidation characteristics of boron-containing alloys. A series of alloys containing 18 and 20 percent chromium with various balances between nickel, cobalt, iron, tungsten, molybdenum and boron were subjected to oxidation tests in air at 1650, 1830 and 2012 degrees F. The high temperatures served to accelerate the tests and emphasized the effect of boron which was not readily noticeable at temperatures below 1650 degrees F.

The specimens consisted of cylinders approximately 1½ inches long by ⅞-inch in diameter, machined from castings. The cylinders were held at temperature in an electric furnace with free access to air. The tests at 1650 and 1830 degrees F were of four weeks' duration while the exposure to 2012 degrees F was for one week. Weight loss rather than gain was measured because of the tendency for these scales to freely exfoliate. The specimens were cleaned after exposure by lightly sand blasting to remove adherent portions of the scale.

Table I lists the compositions of the pertinent alloys exposed and their oxidation rates for each temperature investigated. The alloys are grouped to emphasize the effect of certain elements. The Group I alloys indicate the effect of both boron and cobalt. Figure I shows boron content versus oxidation rate for alloys of 18% chromium, 15% tungsten, two cobalt levels and balance iron. The solid line represents alloys containing 40% cobalt and the broken line those alloys containing 60% cobalt. The adverse effect of both boron and cobalt is emphasized at the higher temperature. The data suggest the possibility of a linear relationship between boron content and oxidation rate in the range studied.

The adverse effect of high iron contents in the alloys is indicated by Groups II and III. (Table I) The oxidation rates, at 2012 degrees F, of the Group II alloys versus their iron content is shown in Figure 2. These alloys consisted of 18 to 20% chromium 20-35% cobalt, 0-20% nickel, 4% molybdenum and 4% tungsten. The increase in iron was largely at the expense of the nickel content. Boron contents ranged from 0.40 to 0.62% and are indicated for each point on the curve by the figures in parentheses. The data indicate that above 31% iron a severe loss in oxida-

★A paper delivered at the Ninth Annual Conference, National Association of Corrosion Engineers, Chicago, Ill., March 16-20, 1953.

WILLIAM O. BINDER—In charge of the Technical Service and Development Laboratory, Electro Metallurgical Company, a division of the Union Carbide and Carbon Corp., Niagara Falls, N. Y. He holds a degree in metallurgical engineering from Case Institute, 1936. He has been employed in the metallurgical laboratory of The Dow Chemical Co., Midland, Mich., 1931-36; Union Carbide and Carbon Research Laboratories, Niagara Falls, N. Y., 1936-52 and since then with his present company. He has published many technical articles on stainless steel corrosion and is chairman of the High-Alloys Committee of the Welding Research Council of the Engineering Foundation.

EDWARD D. WEISERT—Head of the Technical Data Branch of Applied Research and Development Department of Haynes Stellite Company, a division of the Union Carbide and Carbon Corp., Kokomo, Ind., he has been employed by Haynes Stellite since graduation from University of Michigan in 1950. He holds a BS in metallurgical engineering and a BS in Chemical Engineering. He formerly was employed as research assistant at the Engineering Research Institute, University of Michigan, and during World War II was a navigator of combat bombers with the Eighth Air Force based on England. He is a member of ASM and NACE.

Abstract

During an investigation of a series of cast chromium-nickel-cobalt-iron alloys, it became of interest to gain some indication of the effect of boron on the oxidation resistance of this family of alloys. A series of alloys containing 18 and 20 percent chromium with various balances between nickel, cobalt, iron and boron were subjected to oxidation tests in air at 1650, 1830 and 2012 degrees F. Temperatures somewhat above those encountered in gas turbine applications were chosen to accelerate the attack since the effect of boron was not readily noticeable at temperatures below 1650 degrees F.

Results of this investigation indicate that iron and boron and, to a lesser extent, cobalt have an adverse effect on the oxidation resistance. Molybdenum strongly decreases the alloys' resistance to oxidation. X-ray diffraction work indicated that protective Cr_2O_3 scales are not compatible with high boron contents, if the balance of the base alloy elements is not controlled. Boron was found to promote the formation of complex spinel and wolframite type oxides.

It was concluded that while boron has an adverse effect on the oxidation resistance of chromium-nickel-iron-cobalt alloys, boron-bearing alloys may be designed which have oxidation resistance comparable to those without boron by proper control of composition. This may be accomplished primarily by keeping the iron content below 6 percent, through the use of tungsten rather than molybdenum as a strengthening agent and by avoiding excessive cobalt contents, largely through replacement with nickel.

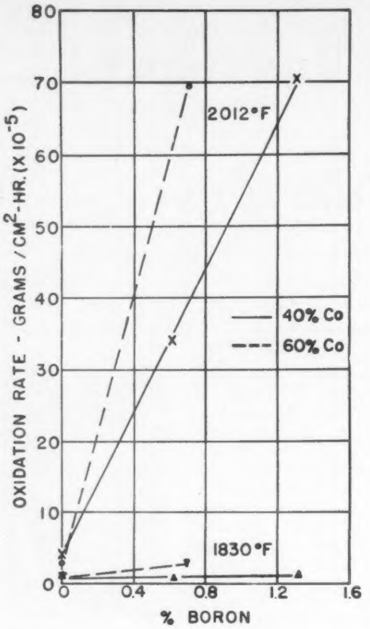

Figure 1—The influence of cobalt and boron on the oxidation resistance of Group I alloys (18Cr-15W).

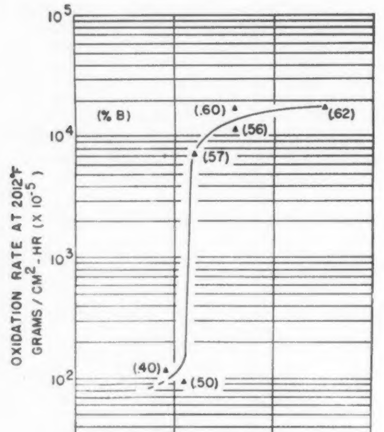

Figure 2—The influence of iron on the oxidation resistance of Group II alloys.

TABLE I—Oxidation Rates of Boron-Containing Alloys

		COMPOSITION—Percent								OXIDATION RATE GRAMS/CM²—HR(X10⁻⁵)		
Group	Heat	Cr	Ni	Co	Fe	Mo	W	B	C	4 Weeks At 1650° F.	4 Weeks At 1830° F.	1 Week At 2012° F.
I	K 230	18	..	40	25	...	15	...	.07	0.70	0.94	3.92
	K 112	18	..	40	24	...	15	.62	.07	0.46	0.57	34.1
	K 113	18	..	40	23	...	15	1.31	.05	0.12	1.45	70.4
	K 105	18	..	60	5	...	15	...	.08	0.61	0.87	2.74
	K 107	18	..	60	4	...	15	.70	.10	....	2.96	69.3
II	J 859	20	20	20	29	4	4	.40	.12	0.60	9.04	119.0
	K 325	18	20	20	31	4	4	.50	.10	0.78	5.96	95.0
	J 672	18	4	35	32	4	4	.57	.08	1.04	2.33	7,200.
	J 814	18	15	20	36	4	4	.56	.10	0.80	73.5	11,300.
	K 324	18	..	35	36	4	4	.60	.05	2.29	1,700.	17,000.
	J 861	18	..	20	45	4	4	.62	.10	....	3,500.	16,800.
III	K 305	18	20	40	4	...	15	.38	.14	0.64	0.53	4.6
	K 295	18	20	40	10	...	10	.40	.13	0.64	4.02	8.19
	J 848	18	15	20	35	...	10	.31	.09	2.55	6.07	49.8
IV	J 847	20	20	20	22	...	15	.41	.08	0.71	4.61	28.0
	K 174	18	20	20	24	7.5	7.5	.47	.08	1.36	9.57	83.8
	K 173	18	20	20	24	15.0	...	.45	.10	3.14	22.1	128.0
V	L 113	18	..	40	26	...	15	...	.06	0.70	0.94	3.92
	K 112	18	..	40	24	...	15	.62	.07	0.46	0.57	34.1
	K 113	18	..	40	23	...	15	1.31	.05	0.12	1.45	70.4
	K 171	18	4	35	30	10	...	.47	.09	4.54	30.7	398.0
	K 305	18	20	40	4	...	15	.38	.14	0.64	0.53	4.6

TABLE II—Constitution of Scales Formed in Air at 2012° F

	After 1 Hour Exposure		After 18 Hours Exposure		After 139 Hours Exposure	
Heat No.		Intensity Ratio		Intensity Ratio		Intensity Ratio
L113 (0%B)	*Co (FCC Matrix)	..	*$(Co,Fe)O \cdot (Cr,Fe)_2O_3$	50	$(Co,Fe)O \cdot (Cr,Fe)_2O_3$	65
	Cr_2O_3	70	Cr_2O_3	35	$(Co,Fe)O \cdot WO_3$	25
	$(Co,Fe)O \cdot (Cr,Fe)_2O_3$	30	Co (FCC Matrix)	..	Cr_2O_3	5
	CoO	Trace	$(Co,Fe)O \cdot WO_3$	15	CoO	5
K112 (0.62%B)	*$(Co,Fe)O \cdot (Cr,Fe)_2O_3$	55	*$(Co,Fe)O \cdot (Cr,Fe)_2O_3$	65	$(Co,Fe)O \cdot (Cr,Fe)_2O_3$	60
	Co,(FCC Matrix)	..	$(Co,Fe)O \cdot WO_3$	30	$(Co,Fe)O \cdot WO_3$	30
	$(Co,Fe)O \cdot WO_3$	30	Cr_2O_3	5	Cr_2O_3	10
	Cr_2O_3	15	Co (FCC Matrix)	..		
K113 (1.31%B)	$(Co,Fe)O \cdot (Cr,Fe)_2O_3$	60	$(Co,Fe)O \cdot (Cr,Fe)_2O_3$	60	$(Co,Fe)O \cdot (Cr,Fe)_2O_3$	65
	$(Co,Fe)O \cdot WO_3$	30	$(Co,Fe)O \cdot WO_3$	30	$(Co,Fe)O \cdot WO_3$	30
	Cr_2O_3	10	Cr_2O_3	10	Cr_2O_3	5
K305 (Good Base)	*Co (FCC Matrix)	..	$(Co,Fe,Ni)O \cdot (Cr,Fe)_2O_3$	30	$(Co,Fe,Ni)O \cdot (Cr,Fe)_2O_3$	40
	Cr_2O_3	60	$(Co,Fe)O \cdot WO_3$	30	$(Co,Fe)O \cdot WO_3$	35
	$(Co,Fe,Ni)O \cdot (Cr,Fe)_2O_3$	40	CoO	10	CoO	15
	$(Co,Fe)O \cdot WO_3$	Trace	Fe_3O_4	10	Cr_2O_3	10
	WO_2, WO_3, NiO	Traces	Fe O	10	Ni O	Trace
			Cr_2O_3 & Co_2O_3	10		
			WO_2, Ni O	Traces		
K171 (Poor Base)	*$(Co,Fe)O \cdot (Cr,Fe)_2O_3$	70	$(Co,Fe)O \cdot (Cr,Fe)_2O_3$	100	$(Co,Fe)O \cdot (Cr,Fe)_2O_3$	100
	Co O	30	Cr_2O_3, NiO, MoO_3	Traces	Ni O	Trace
	Cr_2O_3, Ni O, MoO_3	Traces				

Note: The intensity ratios are intended as a rough indication of the percent of each oxide in the scale. They were obtained by comparing the height of the strongest line for a given oxide to the sum of the heights of the strongest lines for each oxide.
* Scale examined in situ.

tion resistance is encountered. It will be noted that the alloys above 31% iron contained from 6 to 22 points more boron than those with less iron content. How much loss of oxidation resistance resulted from each individual element could not be resolved from the data. However, their combined effect is clearly indicated. All of the specimens in Group II, with more than 31% iron oxidized completely in less than the test duration. The approximate time for complete oxidation was noted to obtain a rough value for the rates, as shown.

Somewhat lower iron contents are dealt with in the Group III alloys. These alloys have a base of 18% chromium, 15 to 20% nickel, 20 to 40% cobalt and 10 to 15% tungsten. Figure 3 compares the oxidation rates for the alloys at 2012 degrees F with their iron content. Again the parenthetical figures refer to the boron content. Iron appears to be solely responsible for increasing the oxidation rate. It is interesting to note that presence of iron appears more detrimental than cobalt, since the lower two points represent 40% cobalt alloys while the 34% iron alloy contained only 20% cobalt. The high iron alloy is also noted to have the lowest boron content. The oxidation rates of the Group III alloys are considerably lower than those of Group II. The major difference is the absence of molybdenum in the Group III alloys.

Molybdenum was found to accelerate the oxida-

tion of the complex, boron-bearing alloys, as shown by the Group IV alloys. The oxidation rates of these 18 to 20% chromium, 20% nickel, 20% cobalt, 22 to 24% iron and 0.41 to 0.45% Boron alloys is compared with the molybdenum-tungsten balance, in Figure 4. The substitution of tungsten for molybdenum was found to greatly increase the oxidation resistance of the alloy.

An X-ray diffraction study was made of the scales formed on the Group V alloys, after exposure to air at 2012 degrees F for 1, 18 and 139 hours. The first three alloys had similar bases, namely, 40% cobalt, 23-26% iron, 18% chromium and 15% tungsten. Boron was at the levels 0%, 0.62% and 1.31% in heats L-113, K-112 and K-113 respectively. Two other alloys containing boron and representing good and poor base composition design, were similarly exposed. These were heat K-171, a high iron alloy with molybdenum and heat K-305, a low iron alloy with no molybdnum. Figure 5 shows the five specimens after exposure to 2012 degrees F for 1 hour.

The constitution of the scales formed on the Group V alloys is indicated in Table II. The lighter scales were examined in situ, while the heavier scales were removed and ground. A Norelco spectrometer was used for the diffraction work. The data for those specimens examined in situ are preceded asterisks in Table II. Some indication of the extent to which these alloys scaled is indicated by the intensity of reflections from the face-centered cubic cobalt matrix. The constituents are listed in decreasing order of intensity of their reflection. In general, the scales were found to consist of chromic oxide, complex spinels, a tungstate of the wolframite type and several simpler oxides. After a one-hour exposure, the scale of the alloy with no boron (L-113) consisted largely of chromic oxide, some spinel and a trace of cobalt monoxide. As the boron content is increased the spinel becomes predominant and the complex tungstate begins to appear in appreciable quantities, while the presence of chromic oxide is decreased.

The effect of time at temperature on the alloy scale with no boron is analogous to the effect of increasing boron content, as just described. The spinel soon dominates the scale and the formation of the tungstate increases with time while the simpler chromic oxide becomes a minor constituent. This same trend is followed by the alloys containing boron (heats K-112 and K-113). It is apparent then, that boron does not exert a direct influence on the constitution of the scales formed on the alloys considered; rather, it appears to influence the rate of formation of certain of the constituents. Primarily, the boron effect is to accelerate the formation of complex spinels, at the expense of the more protective chromic oxide and to promote the formation of the wolframite type tungstate. This effect is obtained without concentration of boron in the scale since chemical analyses of the one-hour scales of heats K-112 and K-113 showed the boron contents in the scales to be at approximately the same level as in the alloys. The boron effect may be related to its slagging powers as an oxide. The scales formed on the high boron alloy

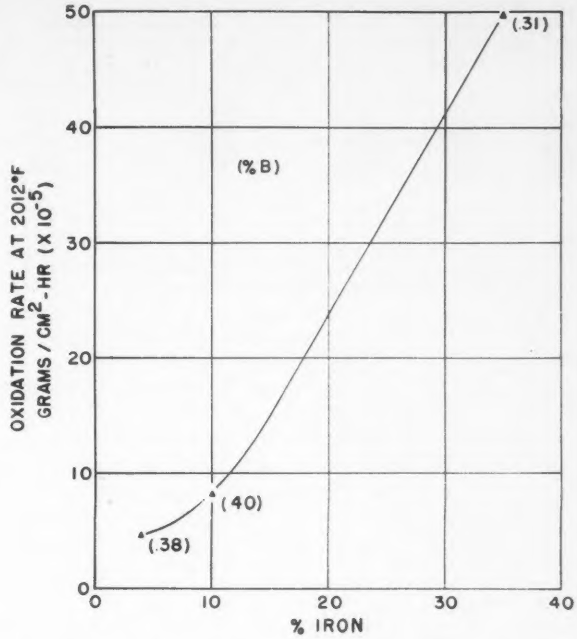

Figure 3—The influence of iron on the oxidation resistance of Group III alloys.

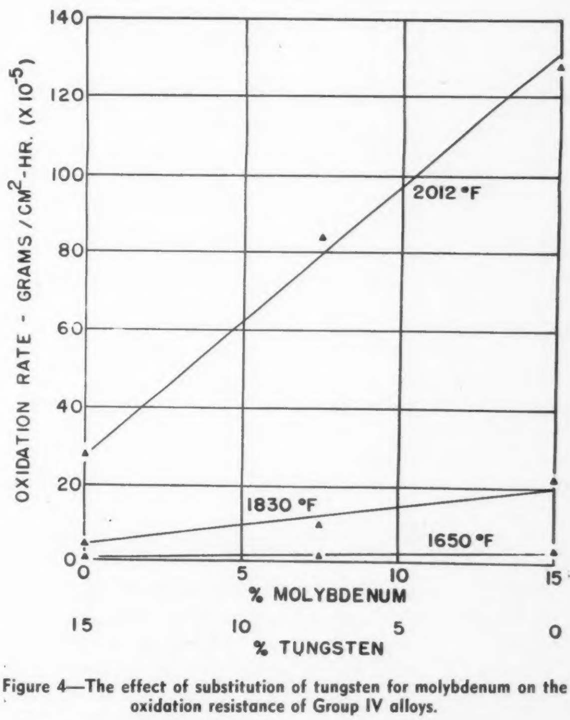

Figure 4—The effect of substitution of tungsten for molybdenum on the oxidation resistance of Group IV alloys.

had a distinctly glassy or wet appearance in contrast to the dry appearance of those with no boron.

The comparison of a good base composition design with a poor base design again emphasized the inability of a spinel type oxide to inhibit the rate of oxidation of these alloys. The good base design (heat K-305) contained 0.38% boron yet showed a high

Effect of varying boron in a 40Co-18Cr-15W-bal Fe base

Effect of base design on boron-containing alloys

(1) (2) (3) (4) (5)

Figure 5—Oxidation characteristics of some high temperature boron-containing alloys. (1) L 1113, No B. (2) K 112, 0.62 B. (3) K 113, 1.31 B. (4) Poor base, 0.47 B. (5) Improved base, 0.38 B.

chromic oxide content in the one-hour scale and with time followed the general pattern of the no-boron alloy, L-113. The poor base resign, (heat K-171) containing 0.47% boron, had a preponderance of spinel in its one-hour scale and the scale was essentially all spinel after the 18-hour exposure. Molybdenum oxides formed from this alloy probably volatilized rapidly at the temperature involved.

The five alloys were also checked metallographically, after a two-hour exposure at 2012 degrees F. No intergranular oxidation was apparent. Some of the alloys exhibited sub-surface oxidation, notably heat K-112. While the sub-surface oxidation was more prevalent in the grain boundary areas, it also occurred generally and the oxidized areas in the grain boundaries were at about the same distance from the metal surface as were those within the grains.

From the foregoing, it may be concluded that while boron has an adverse effect on the oxidation resistance of chromium-nickel-cobalt-iron alloys, boron-bearing alloys may be designed which have usable oxidation resistance by proper control of composition. This may be accomplished primarily by keeping the iron content below 6%, through the use of tungsten rather than molybdenum as a strengthening agent and by avoiding excessive cobalt content, largely by replacement with nickel. Such base designs are believed to increase oxidation resistance by promoting the presence of the protective Cr_2O_3 type oxide and by inhibiting the formation of complex spinels and tungstates.

Discussions

Hydrogen Blistering of Steel in Hydrogen Sulfide Solutions. By T. Skei, A. Wachter, W. A. Bonner and H. D. Burnham. *CORROSION*, Vol. 9, No. 5, 163-172 (1953) May.

Remarks by Harry Gordon Bennett, British American Oil Company, Toronto, Canada:

What is the ratio of the formation of HCN when using natural catalyst as compared to formation using synthetic catalyst? It has appeared to us from talking to various operators of catalytic cracking units that occurrence of hydrogen attack is more pronounced in those units operating on natural catalyst. We understand formation of HCN is greater with natural catalyst than with synthetic.

Reply by William A. Bonner, Shell Oil Company, Wood River, Ill.:

Hydrogen cyanide production when using natural catalyst is approximately twice that obtained when using synthetic catalyst in normal catalytic cracking operations.

Question by Donald L. Burns, 4545 Hollywood Drive. Port Arthur, Texas:

Does the author have information on the quantity of water used per MCF of gas processed in water-washing the gas to reduce hydrogen penetration?

Reply by T. Skei:

Extensive water washing of the gas stream from catalytic cracking operations was applied as a temporary relief measure and gave substantial reduction in frequency and severity of hydrogen blistering. Water injection rate during this treatment was 13,800 gallons per MCF of gas processed.

Anonymous Questioner:

Do you know of hydrogen blistering occurring on thermal reforming process at 1025 degrees F and 150 psi?

Reply by Lewis S. Wright, 1409 Winchester, Ashland, Ky.:

A high temperature (1035 degree F) transfer line blistered during operation after pressure was released on a thermal reforming unit from 700 to 165 psi. Blisters penetrated wall thickness of 4-inch Sch. 80 pipe on inside radius of a 4-foot bend approximately 30 feet from back pressure control valve. Blisters were ½-inch diameter and filled with coke.

Pipe wall was bulged inward as well as outward indicating typical hydrogen blistering. Metallurgical analyses of the pipe after failure are as follows:

Carbon	.15	* Recheck .205
Mang.	.50	
Phos.	.015	
Sul.	.022	
Sil.	.05	
Cir.	.01	
Ni + Cu	.05	
Mo.	.04	

* Recheck of carbon by drilling from center wall of pipe.

The Amount and Distribution of Corrosion. By H. H. Uhlig. A lecture delivered at Ninth Annual Conference, National Association of Corrosion Engineers, Chicago, Ill., March 16-20, 1953. Unpublished.

Question by Lee H. Elizer, P.O. Box 1284, Charlotte, N. C.:

What is the effect of ozone on the adsorbed oxygen film on a black iron surface?

This question was prompted by the following experience. For three years an air washer operated with no sign of pitting. An electrolytic precipitator was then installed 13,000 volts on one set of electrodes and 23,000 volts on the other. The airstream passed through the precipitator and then through the air washer. During the first few months of operation there were no signs of pitting. Then there was a long drought. Then tubercles ½-inch high were observed over the floor of the air washer. Under each yellow tubercle was a pit and the metal was black and shiny. Thank you for any comments.

Reply by H. H. Uhlig:

Pitting under tubercles which form on iron or steel is a common experience and is not necessarily connected with the formation of ozone or any other reaction products produced by a dust precipitator. In other words, the tubercles may have formed as they did after a given time whether or not the precipitator was in use. Ozone and nitric acid produced by high voltage dust precipitators accelerate general corrosion of iron, but their effect on rapidity of tubercle formation has not been studied, so far as I know.

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Topic of the Month

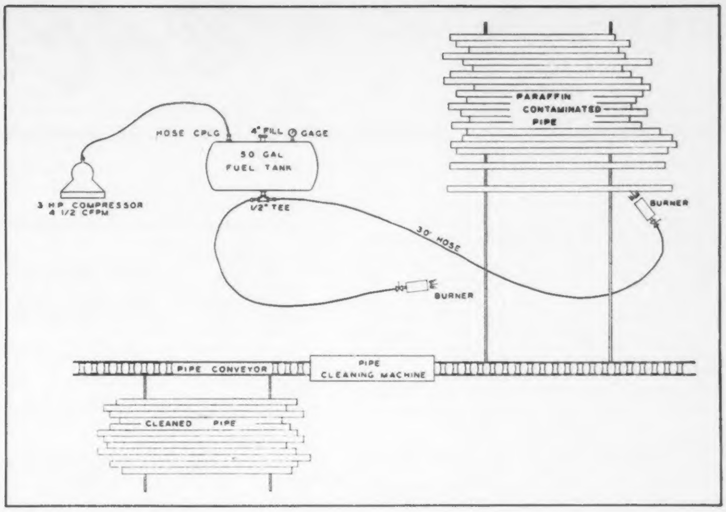

Figure 1—Diagrammatic layout of pipe cleaning setup.

Rapid, Low-Cost Operation

Portable Burner Cleans Exterior of Pipe Contaminated With Paraffin

*By GAINES LASTER**

GAS FIRED burning apparatus frequently has been used to clean contaminated pipe at coating yards where natural gas was available but on a recent occasion it was necessary to improvise a burner that would facilitate pipe cleaning at a location without a supply of natural gas.

The pipe was contaminated on the interior with a heavy coating of paraffin. The stock pile consisted of several thousand feet of pipe having joints of various lengths, all of which had been in yard storage for approximately two years.

During the summer months the paraffin had run out the ends of the shorter joints and thereby contaminated several feet of exterior surface at the ends of longer joints. Inspection revealed that very few of the longer joints had escaped contamination.

Conventional cleaning machines would not remove the paraffin satisfactorily, detergents and cleaning solutions were not sufficiently effective and live steam was only partially effective.

The problem was ultimately solved by use of a portable type burning apparatus fabricated from a small engine-driven air compressor, two conventional type burners having regular half-inch hose, and a 50-gallon tank salvaged from a discarded "dope" kettle. Refer to Figure 1.

Cost of the apparatus was approximately $200 and it could be operated on kerosene or Diesel fuel. Operating pressure was maintained at approximately 60 psi.

Using one torch at each end of the stock pile and rolling pipe past the burner operators, it was possible to completely burn the paraffin from the exterior of the pipe at an average rate of a joint of pipe per minute. This amounted to the processing of approximately ten thousand feet of pipe per 8-hour working day.

Following the removal of paraffin the pipe was rolled onto a stationary conveyor and then fed into a conventional type cleaning machine, from which it was moved down the conveyor and stock piled as shown by the drawing.

The operating cost of the paraffin removal amounted to approximately one fourth of a cent per foot of pipe processed, as may be seen from the following analysis:

16 man-hours @ $1.25	$20.00
50 gal. diesel fuel @ $0.13	6.50
2 gal. gasoline, for compressor engine	0.50
Total Cost	$27.00

By dividing $27.00 by the 10,000 feet of pipe cleaned per day the unit cost for paraffin removal was found to be $0.0027 per ft.

It should be pointed out that the internal deposit of paraffin in this pipe was not considered objectionable for the purpose for which the pipe was to be subsequently used, so it was not necessary to remove the paraffin from the interior of the pipe.

* Tulsa Pipe Coating, Inc., Tulsa, Okla.

NACE News

Hamilton-Niagara Section Host to 75 at Dundas

Hamilton-Niagara Section was host at a June 25 meeting held at Hotel Collins, Dundas, Ont., for Toronto Section NACE and Southern Ontario Committee on Electrolysis. There were 75 present to hear W. F. Fair of Koppers Company speak on "Protective Coatings," in which pipe coating and wrapping materials were covered.

Formal election of officers was held with H. W. Hyslop of United Gas and Fuel Co. of Hamilton, Ont., elected section trustee. Rules and regulations for the section were presented and approved.

66 Guests Attend Permian Basin Meeting

Sixty-six guests and 20 NACE members were present at the July 13 meeting of Permian Basin Section. The meeting, sponsored by Permian Basin Section, was a joint meeting with American Institute of Mining and Metallurgical Engineers and the Texas Society of Professional Engineers.

Y. W. Titterington of Pipeline Anode Corp., Tulsa, spoke on "Cathodic Protection Primarily as Applied to Pipe Lines." John A. Knox, section secretary-treasurer, issued an invitation to attend the Permian Basin Corrosion Tour to be held September 30-October 2. No business was transacted.

Postoffice Changes to Affect Corrosion Mailing

A change in the regulations of the United States Post Office necessitates a change in the practice of the National Association of Corrosion Engineers with respect to copies of Corrosion magazine undeliverable because of incorrect address. It has been the association's custom, when an undelivered magazine was returned to NACE Central Office, to redispatch the copy to the member or subscriber when the correct address was learned.

The post office will no longer return the undelivered copies to NACE, but instead will return a post card notice to the effect that the magazine was undelivered. The magazine will be sent to the dead letter office and ultimately destroyed. In view of this circumstance the association will no longer be able to remail the misdirected copy. Address changes made available through this routine will be made and the next issue of Corrosion will be dispatched.

Persons who fail to receive copies of Corrosion because of failure to notify Central Office of address changes, will be obliged to purchase a substitute copy from the association.

NACE MEETINGS

CALENDAR

Oct.
7—Southern New England Section.
20—Baltimore Section.

Regional Meetings

Oct.
7-9—South Central Region. Mayo Hotel, Tulsa. Technical papers, discussions, committee meetings.
7—Northeast Region. At New Haven, Conn. Technical session beginning at 2 pm with three papers scheduled. Social hour, dinner. Headquarters Hotel Taft.

Nov.
12—South East Region. Birmingham, Ala.
19-20—Western Region, Biltmore Hotel, Los Angeles. Technical committee meetings, symposia on refinery and aircraft corrosion.

Phenolic, Rubber Linings Topic at Houston Meet

Baked Phenolic and Rubber Linings in Corrosive Service, was the scheduled topic of G. J. Duesterberg, Plastic Applicators, Inc., Houston, at the August 11 Houston Section meeting.

Gordon Conference Honors Members of NACE

Two of the three new officers for the Gordon Research Conference on Corrosion of the American Association for the Advancement of Science are members of the National Association of Corrosion Engineers. The third officer, Earl A. Gulbransen, of Westinghouse Electric Corporation's Research Laboratories at East Pittsburgh, Pa., received the NACE 1952 Willis Rodney Whitney Award for achievements in the field of corrosion science. Dr. Aaron Wachter, named chairman, is vice-president of NACE; Dr. Gulbransen was named vice-chairman and Herman A. Liebhafsky, of the General Electric Company Research Laboratory at Schenectady, was named recording secretry.

Dr. Wachter and Dr. Gulbransen are now delegates to the Inter Society Corrosion Committee from the Gordon Conference.

The annual conference, held at Colby College, New London, N. H., July 20-24, had as a theme "A Critical Review of Modern Fundamental Concepts of Corrosion." Registration was 122, a record, and 25 applications to attend were turned down.

Northeast Region Outlines Program to Feature 3 Papers

Three papers by men prominent in the corrosion field will be featured on the technical program for Northeast Region's 1953 Fall Conference at Hotel Taft, New Haven, Conn., October 7. Scheduled to give papers beginning at 2 p.m. are R. B. Hoxeng, United States Steel Company; William B. Robertson, Yale University, and H. R. Copson, International Nickel Co., Inc.

The technical session will be followed by a social hour and by dinner beginning at 7 p.m. An entertaining dinner speaker is expected. Those intending to spend the night are advised to make reservations directly with Hotel Taft.

Persons responsible for arrangements point out an added reason for those attending this meeting to bring their wives —the colorful autumn hued foliage in New England at this time of the year which is considered by many to be unequalled for beauty anywhere in the United States.

Recipients of ASTM Awards Are Named

The American Society for Testing Materials has announced Awards of Merit to ten technical leaders in the field of engineering materials who have rendered outstanding service to the society, particularly in its technical committee work.

Three other awards and a medal were given to outstanding men in the society, among them the Sam Tour Award to J. R. McDowell, of Westinghouse Electric Corp. for his paper, Fretting Corrosion Tendencies of Several Combinations of Materials. The awards were presented at the society's 56th Annual Meeting at Atlantic City, N. J., in June.

Sillcox Nominated to Head ASME in 1954

Lewis K. Sillcox, vice chairman of the board of directors of New York Air Brake Company has been nominated the 1954 president of the American Society of Mechanical Engineers. Also nominated were five regional vice presidents and two directors-at-large. Election will be by letter ballot.

Furman Is Honored

Nathaniel Howell Furman of Princeton University has been selected to receive the 1953 Palladium Medal of The Electrochemical Society. The award will be conferred for outstanding contributions to the field of analytical chemistry on September 15 at Wrightsville Beach, North Carolina.

Texas A & M Corrosion Course Outline Given

A tentative program for the Corrosion Short Course to be given at Texas A & M College, College Station, September 22-25, has been prepared. J. D. Lindsay, head of the college's chemical engineering department, in charge of the course, said basic corrosion subjects would be covered, including fundamentals, materials of construction, coatings, cathodic protection, instrumentation and special topics.

Small group discussions have been scheduled for the evening of September 23.

Workers in corrosion and executives of companies concerned with corrosion are invited to attend. Registration will be limited and a registration fee of $25 will be charged.

NACE Cooperating

The school is giving the course in cooperation with the South Central Region, National Association of Corrosion Engineers. A steering committee from NACE, consisting of R. A. Brannon, Humble Pipe Line Company; A. B. Campbell, NACE executive secretary; Charles G. Gribble, Jr., The Metal Goods Corp., all of Houston; Norman Hackerman, University of Texas, Austin; Gustave Heinemann, Columbia-Southern Chemical Corp., Corpus Christi, Texas; T. F. P. Kelly, Kelly-Mavor Co., Houston; David Henry Levy, Magnolia Pipe Line Co., Dallas; John E. Loeffler, Thornhill-Craver Co., Houston; Oliver Osborn, Dow Chemical Co., Freeport, Texas; A. L. Stegner, Tennessee Gas Transmission Co., Houston; Starr Thayer, consulting engineer, Houston; William A. Wood, Jr., Products-Research-Service, Inc., Houston.

Tentative Schedule

Tuesday Morning, Sept. 22, J. D. Lindsay, presiding.

9 a.m.—Welcome, A & M College official. Response, Walter Rogers, NACE president. Membership in NACE, A. B. Campbell, NACE. The NACE Education Committee, Norman Hackerman, University of Texas. The South Central Region NACE, Harry E. Waldrip, chairman, Gulf Oil Corp., Houston.

9:30 a.m.—Fundamentals of Corrosion, Thomas P. May, The International Nickel Co., Inc., New York City.

10:45 a.m.—Fundamentals of Cathodic Protection, Starr Thayer, consultant, Houston.

Tuesday Afternoon, Sept. 22, John E. Loeffler, presiding.

2, 3 and 4 p.m.—Three one-hour periods on materials of construction. Speakers to be named.

6 p.m.—Barbecue, assembly in Student Center lobby.

Wednesday Morning, Sept. 23, L. G. Sharpe, Humble Pipe Line Company, presiding.

9 a.m.—Chemical Plant Design Problems from the Corrosion Prevention Aspect, Howard E. Dick, Products-Research-Service, Inc., Westwego, La.

10 a.m.—Surface Preparation of Steel Structures and Application, Harry E. Waldrip, Gulf Oil Corp.

11 a.m.—Production of Paints and Coatings for Industry, Joseph E. Rench, Jr., Napko Paint & Varnish Co.

Wednesday Afternoon, Sept. 23, John R. Ligon, Sinclair Pipe Line Co., Fort Worth, Texas, presiding.

2 p.m.—Protective Coatings for Underground Structures, L. G. Sharpe, Humble Pipe Line Co.

3 p.m.—Principles of Cathodic Protection, Marshall E. Parker, Cormit Engineering Co., Houston.

4 p.m.—Application of Cathodic Protection to Distribution Systems, C. L. Woody, United Gas Corp., Houston.

7:30 p.m.—Small group discussions under direction of Oliver Osborn, Dow Chemical Co.

Thursday Morning, Sept. 24, Harry E. Waldrip, presiding.

9 a.m.—Application of Cathodic Protection to Pipe Lines and Tanks, O. W. Wade, Transcontinental Gas Pipe Line Corp., Houston.

10 a.m.—Application of Cathodic Protection in Industrial Plants, Derk Holsteyn, Shell Oil Co., Houston.

11 a.m.—Use of Cathodic Protection in Salt Water, E. P. Doremus, Cathodic Protection Service, Houston.

Thursday Afternoon, Sept. 24, A. L. Stegner, presiding.

2 p.m.—Instruments — Theory, Characteristics, Design and Manufacture, Lyle R. Sheppard, Shell Pipe Line Corp., Houston.

3 p.m.—Instruments—Application to Field Use, C. L. Woody.

(Continued on Page 4)

Whitney Will Address New York Section

F. L. Whitney, Jr., of Monsanto Chemical Co., St. Louis, Mo., is scheduled to address Metropolitan New York Section on September 23 at a dinner meeting. The title of his talk "Case Histories Illustrating Methods of Combating Corrosion with the Use of Coatings."

Metropolitan Section, organized in 1948 with 180 members, now has 440 members. At the beginning of the section's fifth year F. J. LeFebvre, secretary, said a well-rounded program has been arranged for the year and there is every indication the section's fifth will be one of its best years.

37 Laboratories Probe Pollution of Air

Thirty-seven laboratories and universities are conducting research into the problem of air pollution, a survey published by the American Society for Metals Committee on Air Pollution Controls shows. These inquiries range from the Argonne Laboratory's search for an instrument capable of determining quantitatively the amounts of freon 12 in air to Ontario Research Foundation's measurements of dustfall, atmospheric dust, gas and vapor concentration, meteorological studies and determination of "corrosion potential."

The committee was formed to provide a clearing house for information on air pollution control projects and trends.

Diffraction Conference Scheduled November 5-6

Technical sessions on Instrumentation and Methods, Metals, Recrystallation and Preferred Orientation and Structure of Polymers are being arranged for the Eleventh Annual Pittsburgh Diffraction Conference. Papers on these subjects and on general diffraction subjects are being accepted. The sessions will be held at Mellon Institute, Pittsburgh, Pa., November 5-6.

Persons interested in submitting papers may send titles for consideration to Program Chairman E. E. Wicker, United States Steel Corp., Res. & Dev. Lab., 234 Atwood St., Pittsburgh 13, Pa.

NYU Offers Courses On Surface Technology

Two surface technology courses will be offered during the fall term at New York University's division of general education. They are: Fundamentals of Paint, Varnish and Lacquer Technology, 8 to 10 pm, Wednesdays, Sept. 23-Jan. 20. It will cover coatings for protection, decoration and functional purposes, raw materials, manufacture and other phases. Seminar on New Development in Organic Finishes, 8 to 10 pm, on Tuesdays, Sept. 22-Jan. 19. This will cover important advances recently made.

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Information on NACE's Corrosion Abstract Card Service may be obtained by writing to Central Office, 1061 M & M Bldg., Houston 2, Texas.

Kettering Is Honored

As a highlight of its annual meeting, in Daytona Beach, Fla., June 18-20, the National Society of Professional Engineers will present the NSPE award to Charles F. Kettering, engineer, inventor, and vice president of General Motors. The award, granted on the basis of meritorious service to the engineering profession has been given only twice before, to former President Herbert Hoover, and to bridge builder D. B. Steinman. The award will be given at a banquet climaxing the three-day meeting. T. Carr Forrest, Jr., Dallas, will be installed as new president of the society.

Illinois Short Course Will Open on October 12

A 5-day short course on cathodic protection will open October 12 at University of Illinois, Urbana. The course, co-sponsored by the National Association of Corrosion Engineers, is the first course to be devoted exclusively to a major area of corrosion science. Instruction will cover economics, management problems, theory, application, design problems, instruments, testing and other phases of the subject. All instructors are NACE members.

Ray Wainwright, associate professor of electrical engineering at the university is coordinator for the course. Registration fee is $47.50 payable to the university. This fee covers $37.50 for lectures, laboratories and demonstrations and $10 for five luncheons on the campus and a banquet. Dittoed notes will be supplied. Registration is limited to 50.

A detailed schedule of the course was published in August CORROSION, Page 13.

Oklahoma U. Seminar

A corrosion seminar has been scheduled at the University of Oklahoma, Norman, on December 1-4 inclusive. Dr. John P. Roberts, in charge of the seminar, is getting the cooperation of Central Oklahoma Section NACE. Dr. C. C. Allen is chairman of the section's committee working with Dr. Roberts.

Texas A & M–

(Continued From Page 3)

4 p.m.—Instruments — Non-Destructive Measurement of Wall Thickness in Chemical Process Equipment, speaker to be named.

7 p.m.—Banquet.

Friday Morning, Sept. 25, Gustave Heinemann, presiding.

9 a.m.—Organization of Corrosion Departments, H. L. Bilhartz, Atlantic Refining Co., Dallas.

10 a.m.—Corrosion Inhibitors, Floyd E. Blount, Magnolia Petroleum Co., Dallas.

11 a.m.—Corrosion by Waters in Once Through Sea Water Systems, W. B. Brooks, Dow Chemical Co., Freeport.

11:30 a.m.—Corrosion by Water in Recirculating Systems, Charles P. Dillon, Carbide & Carbon Chemicals Co., Texas City, Texas.

Registrations and room reservations will be filled in order of receipt by Dr. Lindsay. Accommodations in the A & M Student Center can house about 100 persons. Air conditioned tourist courts are close by.

Schedule for Western Region Meeting Outlined

An opportunity for week-long study and conferences on corrosion will be provided by the Western Region, National Association of Corrosion Engineers November 16-20. A three-day course on cathodic protection will be offered beginning on November 16 by the University of California at Los Angeles. NACE is sponsoring the short course. November 19 and 20 will be devoted to the Third Annual Conference of Western Region NACE, when corrosion problems affecting pipelines, oil refineries and aircraft will be discussed.

The University of California course will be directed toward training personnel in the field installation and maintenance of cathodic protection systems.

At the regional conference some of NACE's technical committees are expected to make reports during the morning of November 19. Technical papers will be presented during the afternoon on gas and water pipeline corrosion. On the following morning papers on corrosion problems in the aircraft industry will be given and in the afternoon of the 20th corrosion problems in petroleum refineries will be discussed.

The week's activities afford an opportunity to listen to and discuss with some of the nation's leading corrosion engineers current corrosion problems and what is being accomplished in controlling corrosion damage.

Western Region Conference Tentative Schedule

Pipeline Management's Approach to Refinery Corrosion Problems by K. E. Kingman, vice-president and manager, Union Oil Company.

American Standards Association Efforts to Establish a Code for Gas Pipelines That Will Meet Approval of all States by F. A. Hough, vice-president, Southern Counties Gas Co.

Metallurgy of Pipe and the Metallurgical Approach to Corrosion Problems in Large Diameter Pipe by Earl R. Parker, Professor Metallurgy, University of California.

Factors Affecting the Corrosion of Aluminum Pipe Used in Sprinkler Irrigation by Mark F. Adams, Associate Chemist, Washington State Institute of Technology, Division of Industrial Research.

Stress Corrosion of Airframe Components by R. N. Hooker and J. L. Waisman, Douglas Aircraft Co.

Vitreous Coatings on Aircraft Parts to Resist High Temperature Corrosion by John V. Long, Director of Research, Solar Aircraft Co.

Role of Organic Inhibitors for Refinery Corrosion Prevention by George E. Purdy, Tretolite Co.

Use of Alloys to Prevent Corrosion in Critical Petroleum Refinery Problems by B. B. Morton, The International Nickel Co., Inc.

BOOK REVIEWS

Ferrous Analysis, Modern Practice and Theory. By E. C. Pigott. Second revised edition, 1953. 690 pages, 8¾ x 5½ inches. Illustrations and tables. John Wiley & Sons, Inc., 440 Fourth Ave., New York, N. Y. Per copy....$12.50

The book gives in detail procedures for analyzing ferrous compounds and lists the various techniques used in analysis. Chapters deal with available analytic techniques and their proper choice. The constituents of iron and steel are arranged alphabetically; there are other chapters on the microchemical analysis of iron and steel, alloys and ores and refractory materials.

Each principal constituent of iron and steel is discussed separately. The proper method and technique for analysis of each constituent is given in detail and an extensive bibliography is given listing books which deal more extensively with specific techniques for analysis.

Tables list the classification and several characteristics of Main Quantitative Techniques, of Special Quantitative Techniques and of Special Semi-Quantitative Techniques.

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Proceedings, American Society for Testing Materials, 1952. Vol.* 52, 1309 pages 5¾ x 9 inches. Illustrated. Published by American Society for Testing Materials, 1916 Race St., Philadelphia, Pa. Price not given.

This hard backed, cloth bound book consists of Committee Reports, Technical Papers and Symposia Proceedings of the ASTM during 1952. The table of contents and subject and author indexes

(Continued on Page 6)

New Specifications Are Listed by ASTM

Of the 63 new materials specifications accepted at the June 28-July 2, 1953, Annual Meeting of the American Society for Testing Materials, the following listed have significance for corrosion workers. Copies of these specifications will be available for sale later from ASTM headquarters, 1916 Race St., Philadelphia 3, Pa., at a nominal charge, usually 25c each, but slightly higher on standards over 16 pages.

Seamless copper tube for refrigeration service (B 280-53 T).

Methods of test for adherence of porcelain enamel and ceramic coatings to sheet metal (C 313-53 T).

Methods of testing for corrosive sulfur in electrical insulating oils (D 1275-53 T).

Method of test for water vapor permeability of shipping containers by cycle method (D 1276-53 T).

Specifications for non-rigid thermoplastic compounds for automotive and aeronautical applications (D 1277-53 T).

Method of test for buffering action of metal cleaners (D 1279-53 T).

Total immersion corrosion test for soak tank metal cleaners (D 1280-53 T).

Method of test for rinsing properties of metal cleaners (D 1281-53 T).

Methods of test for chemical oxygen demand (dichromate oxygen demand) of industrial waste water (D 1252-53 T).

Methods of test for residual chlorine in industrial water (D 1253-53 T).

Methods of test for nitrite ion in industrial water (D 1254-53 T).

Methods of test for sulfides in industrial waste water (D 1255-53 T).

Scheme for analysis of industrial water (D 1256-53 T).

Methods of test for measuring water vapor transmission of materials in sheet form (E 96-53 T).

Reference radiograms of aluminum and magnesium castings (E 99-53 T).

Chemical Exposition

The Eighth National Chemical Exposition of the American Chemical Society will be held October 12-15 at Chicago Coliseum. It is a function of Chicago ACS section.

BOOK REVIEWS

(Continued From Page 5)

cover papers and reports published by the society during the year and includes some papers the text of which does not appear in the 1952 Proceedings but which have been accepted for publication in the ASTM Bulletin or other Special Technical Publications.

Among the reports and papers published in the 1952 proceedings are: Report of Committee A-5 on Corrosion of Iron and Steel; Committee B-3 on Corrosion of Non-Ferrous Metals and Alloys and a Report of Advisory Committee on Corrosion. Other papers on corrosion are: Atmospheric Corrosion of Steel Wires by A. P. Jahn, Atmospheric Corrosion of Low Alloy Steels, by H. R. Copson and A Method of Evaluating Corrosion by Molten Metals by M. A. Cordovi. Proceedings of the symposium of Fretting Corrosion are also published in the book.

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Corrosion—A Short Course. 8½ x 11 inches, 148 pages. February, 1952. Dept. of Conf. & Spec. Activities, University Extension, University of California, Los Angeles 24, Calif.

Per copy $2.00

The book consists of 25 lectures given at a Corrosion Short Course at the University of California, Los Angeles, in cooperation with the National Association of Corrosion Engineers, February 4-8, 1952. These lectures, by men active in the corrosion field in the United States, cover such subjects as the Cost of Corrosion and Corrosion Control in the United States, Corrosion of Non-Ferrous Metals, The Soils, Chemical and Physical Chemical Methods of Applying Coatings to Prevent Corrosion, Theory of Oil Well Corrosion and others. The book is useful for reference and is indicative of the kind of information presented at short courses on this subject.

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Symposium on Conditioning and Weathering. ASTM Special Technical Publication No. 133. 1953. 98 pages, 6x9 inches, paper cover. American Society for Testing Materials, 1916 Race St., Philadelphia 3, Pa.

Per Copy $2.25

Consisting of 10 papers presented at the ASTM 50th Anniversary Meeting, New York, June 24, 1952. Of special significance to corrosion workers are: Fundamentals of Atmospheric Elements by B. C. Haynes; Conditioning and Weathering of Adhesives and Plastics by F. W. Reinhart; Weathering of Some Organic Coatings by E. J. Dunn, Jr.; Weathering Tests on Metallic Coatings by William Blum; Development of a Moisture Resistance Test by C. P. Lascaro; Outdoor Exposure Testing on Racks and Test Fences by K. G. Compton and Accelerated Weathering Devices by R. H. Sawyer.

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Electrodeposition Research. Proceedings of the NBS Semicentennial Symposium on Electrodeposition Research held at the NBS on December 4-6, 1951. National Bureau of Standards Circular 529, 129 pages, 38 figures, 19 tables, buckram bound. Government Printing Office, Washington 25, D. C.

Per Copy $1.50

This volume contains papers given at a symposium sponsored by NBS to encourage further research in this field, to present current research results and problems and to facilitate the exchange of information.

Representing a cross section of research currently being conducted in electrodeposition by industrial, university and government laboratories in Europe and the United States, the papers cover such topics as research on electrodeposition in Great Britain, the United States, France, Germany, Belgium and Holland; electrodeposition research at Battelle Memorial Institute, United Chromium, Inc., the Bureau of Mines, Armour Research Foundation, Westinghouse Electric Corporation and Sylvania Electric Products; research at Enthone, Inc., on metal finishing; brass plating; electroplating in the sleeve-bearing industry; corrosion resistance of copper, nickel and chromium-plated zinc, aluminum and magnesium base die castings; determination of impurities in electroplating baths; effects of impurities in plating solutions; porosity in deposits; correlation of gas permeability of electrodeposits with their weathering behavior; properties of electrodeposited nickel; disposal of cyanide wastes from plating operations; current and metal distribution in electrodeposition; and a new degreasing evaluation test: the atomizer test.

Permian Tour Will Include Modern Refinery

Headquarters for Three-Day Event Will Be at Odessa

An opportunity to inspect corrosion mitigation measures at the modern Cosden Petroleum Company refinery at Big Spring will be given registrants at the 1953 Permian Basin Corrosion Tour. The tour will be held September 30-October 2, with headquarters at Lincoln Hotel, Odessa, Texas. The registration fee, payable to Permian Basin Section NACE, should be sent to John A. Knox, Secretary-Treasurer, P. O. Box 310, Midland, Texas. Hotel registrations should be made directly.

Besides the Cosden refinery, the tour is expected to provide an opportunity for inspection of tanks, pipe lines, well casing and tubing, pumps, heat exchangers and other petroleum equipment. In some cases the 6-year history of the equipment and the corrosion limiting measures taken to preserve it will be revealed. More than 70 exhibits are anticipated, made available by oil companies cooperating with the section in the tour. These exhibits, for the most part are viewed in situ.

Travel to the sites of exhibits is by chartered bus. Conferences after field trips are held to discuss the exhibits visited.

A barbecue dinner by the Odessa Chuck-wagon gang is scheduled. Speakers for after-dinner discussion sessions are scheduled. Small portable items of equipment will be exhibited at Odessa the last night of the tour.

In 1951 the tour was attended by engineers from 38 states and three foreign countries. The results of coating the inside and outside of petroleum production equipment with various types of coatings were viewed and the various means adopted for mitigating corrosion from petroleum were discussed.

Baker Is President Of Alloy Institute

G. A. Baker, vice-president of The Duriron Co., Inc., Dayton, has been elected president of the Alloy Casting Institute. C. K. Lockwood, vice-president of Stainless Steel and Alloys Div., Shawinigan Chemicals, Ltd., Montreal was elected vice-president and E. A. Schoefer, Mineola, N. Y., was reelected executive vice-president and treasurer.

ASM Officers

American Society for Metals officers to take office Oct. 21 have been named as follows: J. B. Austin, U. S. Steel Corp., president; George A. Roberts, Vanadium Alloys Steel Corp., vice-president; W. A. Pennington, The Carrier Corp., treasurer.

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Reprints of material published in Corrosion are usually made only on order. Tentative prices may be obtained from Corrosion, 1061 M & M Bldg., Houston 2, Texas.

British Tin Magazine

"Tin and Its Uses," a periodical review issued by the Tin Research Institute, Fraser Road, Greenford, Middlesex, England, contains abstracted and original articles concerning developments involving tin. The June, 1953 issue, No. 28 did not indicate terms of availability.

Refrigeration Show

A Refrigeration and Air Conditioning Exposition will be held at Cleveland November 9-12.

New ASTE Chapters

Two new chapters of the American Society of Tool Engineers were chartered on the nights of June 22 and 23. They are located at Lansing, Mich. and Canton, Ohio.

AIChE Meeting Set At San Francisco

A national meeting of the American Institute of Chemical Engineers will be held September 13-16 at San Francisco.

Tentative Kansas City Technical Program Given

WHO'S WHO ON KANSAS CITY PROGRAM


DeLong


Fritzlen


Haile


McCormick


Simpson


Stout


Titterington


Watkins


Wenk

W. B. DeLong—Mr. DeLong is in the Engineering Department, Experimental Station, E. I. DuPont de Nemours & Co., Inc., at Wilmington. He is co-chairman of the Chemical Industry Symposium for the 1954 Kansas City Conference.

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Glenn A. Fritzlen—Chairman of the Elevated Temperature Symposium at Kansas City next March. Mr. Fritzlen, Assistant Technical Director, Haynes Stellite Company, Kokomo, Ind., has been with his present employer seven years engaged in work related to high-temperature corrosion. He served as Research Metallurgist, Project Engineer for High-Temperature Alloys, Head of the Physical Metallurgy and Alloy Development Section at Haynes Stellite. A graduate of Purdue University with a BS in metallurgical engineering, he was employed previously by Aluminum Company of America, Lafayette and Allison Division Laboratories, Indianapolis, before entering the Army Air Corps. In the corps he was Assistant Chief of Metallurgical Branch, Materials Laboratory at Wright Field, Ohio, for three years. He spent six months at a technical intelligence officer in the United Kingdom and Germany as liaison officer for material analyses of captured enemy aircraft. He is a member of NACE, AIME, ASM and other technical societies and organizations.

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E. P. Haile—Mr. Haile, co-chairman for the Non-Destructive Testing Symposium at Kansas City, is supervisor of the Corrosion and Inspection Group at Monsanto's Texas Division at Texas City, Texas. He has been active in corrosion and inspection work for seven years. He holds a BS in chemistry from Louisiana State University and a Naval Reserve Commission from the United States Naval Academy. Before joining Monsanto in 1951, he was with Lago Oil and Transport Co., Aruba, N. W. I., in corrosion and inspection work and with A. O. Smith's Houston Works in pressure vessel fabrication.

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L. O. McCormick—Mr. McCormick, at present a Distribution Engineer in the Testing Division of the Electric Distribution Department, Consolidated Gas Electric Light and Power Company of Baltimore, has spent most of his time since 1943 on electrolysis mitigation work. He has been a member of NACE Technical Practices Committee 16 on Electrolysis and Corrosion of Cable Sheaths since its organization. Mr. McCormick, co-chairman of the Electrical and Communications Symposium for the 1954 Conference, has been employed by his present company since his graduation in 1927 from the Engineering School, Johns Hopkins University, with a BE.

(Continued on Page 9)

Ten Symposia, Group Discussions and Round Table Planned

A complete tentative outline of the technical program for the Tenth Annual Conference and Exhibition of the National Association of Corrosion Engineers has been revealed by F. L. Whitney, Jr., Monsanto Chemical Co., technical program chairman. The principal difference from the schedule at the meeting last year will be that morning symposia will end at 11:30.

The tentative schedule follows:

Monday, March 15

9-12 noon—Technical Practices Committee meetings.
2-5 pm—Technical Practices Committee meetings.

Tuesday, March 16

9-10 am—General Business meeting.
10-11:30 am—Corrosion Principles and Non-Destructive Testing Symposia.
2-4:30 pm—Cost of Corrosion and Refinery Industry Symposia.
4:30-5:30 pm—Educational Lecture No. 1.

Wednesday, March 17

9-11:30 am—Pipe Line Coatings, Power and Communication Industry and Atmospheric Pollutants Symposia.
2-4:30 pm—Chemical Industry Symposium and Pipe Line Group Discussions.
4:30-5:30 pm—Educational Lecture No. 2.

Thursday, March 18

9-11:30 am—Cathodic Protection Symposium and General Corrosion Problems. Round Table.
2-4:30 pm—Pipe Line and Underground Corrosion Round Table and Elevated Temperature Corrosion Symposium.
4:30-5:30 pm—Educational Lecture No. 3.

Friday, March 19

9-11:30 am—Protective Coatings and Oil and Gas Production Symposia.

The morning technical sessions were shortened to provide more time for visiting exhibits.

More Officials Named For 1954 Conference

Two more acceptances of responsibility for segments of the technical program to be given at the NACE Tenth Annual Conference and Exhibition at Kansas City in 1954 have been announced as follows:

H. H. Uhlig, head of the corrosion laboratory at Massachusetts Institute of Technology, will be co-chairman of the Cost of Corrosion Symposium.

L. W. Harkemier, Department of Chemistry, Colorado School of Mines, Golden, has accepted co-chairmanship of the Educational Lectures.

Plastic Materials Is K. C. Paper Subject

"The Use of Plastics as Materials of Construction in the Chemical Industry," is the title given a paper by S. W. Shepard, Chemical Construction Corp., Linden, N. J., to be presented during the NACE Tenth Annual Conference and Exhibition at Kansas City. It will be one of the papers in the Chemical Industry Symposium.

Who's Who—

(Continued From Page 8)

A. D. Simpson, Jr.—Chief Engineer of the Operating Division of the United Gas Corp., Houston. Mr. Simpson did his first work on pipe lines for the Texas Pipe Line Company in 1929 when he was rodman and draftsman on mapping and inventory work with headquarters at Odessa. He was first employed by United Gas Corp., in January, 1931, when it was known as the United Gas Public Service Company, as a rodman on a field survey party. He has since held responsible positions with United Gas with headquarters at Lake Charles, Jacksonville, Texas, and Houston. His current responsibilities include construction, maintenance and operation of physical properties of the distribution company in Texas, including valuation, standardization, cathodic protection and radio communication. He is chairman of the Kansas City Pipe Line Coatings Symposium.

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Lawrence E. Stout—Dr. Stout is dean of the School of Engineering, Washington University, St. Louis. A consulting chemical engineer for 25 years, he holds degrees from DePauw University and Ohio State University and has been in the chemistry and engineering schools of Miami University, Oxford, Ohio and Washington University in various capacities since 1923. He is a professor of chemical engineering, chairman of the chemical engineering department at Washington University and since 1948 has been director, Sever Institute of Technology, the graduate division of the School of Engineering, Washington University, St. Louis, Mo. A member of numerous technical societies, he has had about 70 papers published. He is chairman of the General Corrosion Problems Round Table to be held at Kansas City next March.

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Yale W. Titterington—Mr. Titterington, who is with the Pipe Line Anode Corp., Tulsa, has long been active in NACE. His interest in corrosion mitigation extends over more than 15 years. He is chairman of the Pipe Line and Underground Corrosion Round Table to be held during the NACE Kansas City Conference.

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Franklin M. Watkins—Director since 1948 of the Corrosion Engineering Division, Sinclair Research Laboratories, Inc., Harvey, Ill., he holds a BS in chemical engineering and an MS in chemistry from University of Colorado. While a test engineer in General Electric Company's research laboratories, he became interested in the properties of transformer oils, and as a result was employed by Sinclair Refining Company's research department in 1936. He then directed additive synthesis and formulation of petroleum products with additives. Since joining NACE in 1949 he has been chairman of the Chicago Section, and of Technical Practices Committee 9 on Corrosion Inhibitors. He is actively interested in technical practices committee work. He is co-chairman of the Kansas City Refinery Industry Symposium and is expected to be chairman of the same symposium at the NACE's 1955 Conference in Chicago.

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Samuel A. Wenk—Mr. Wenk brings to the chairmanship of the Non-Destructive Testing Symposium at Kansas City many years of experience in this subject and in metallurgy. Before joining Battelle Institute, Columbus, Ohio, in 1948 where he is chief of non-destructive testing research there aimed at developing new methods for detection of flaws in engineering materials, he was chief metallurgist, Bowser, Inc., Fostoria, Ohio. For five years during World War II he served in the Ordnance Department as Chief of Inspection for the Pittsburgh Ordnance District and Chief Production Engineer for Heavy Calibre Ammunition for the Office of Chief of Ordnance. He is a VMI graduate in metallurgical engineering. He is a member of the Non-Destructive Testing Society, ASTM and Sigma Xi.

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Persons interested in joining NACE may get information and application blanks for membership by writing to Central Office, 1061 M & M Building, Houston 2, Texas.

TULSA—Where South Central Region, National Association of Corrosion Engineers, will hold its 1953 meeting. The October 7-9 sessions will be the first held by the region in Tulsa since 1949. The view here of the downtown business district shows the Arkansas River in the background.

Tulsa Program Includes Thirteen Technical Papers

AUTHORS AND ABSTRACTS TULSA PROGRAM

Use of the Null Bridge Method for the Classification of Corrosion Inhibitors by B. L. Cross, Naval Ordnance Test Station, Inyokern, Calif., and Norman Hackerman, University of Texas.

B. L. CROSS—Since March of this year Mr. Cross has been in physical chemistry research and laboratory instrument design at the Naval Ordnance Test Station, Inyokern, Cal. A graduate of the University of Illinois and of the University of Texas, he served in the Army Air Corps from 1942 to 1946.

NORMAN HACKERMAN—Professor of chemistry and director of the Corrosion Research Laboratory at University of Texas, Prof. Hackerman has long been active in NACE affairs. His research interests are principally chemistry and physics of surfaces especially when applicable to metals. A native of Baltimore, he received a PhD in physical chemistry from Johns Hopkins in 1935. He and his students have published in recent years many papers on adsorption on metal surfaces and passivity.

Abstract

A Pearson null bridge was constructed using his original design plus a later design with some additional modifications. Results of high precision were not obtained from the instrument because of its inherent deficiencies. Observed potentials were shown to consist of an IR film drop and an activation over-potential. The latter had the smaller effect on the observed electrode potential.

The instrument was tested on various inhibitors and the results compared to those obtained by more direct methods. These were in fair agreement both in magnitude and direction with results obtained by other methods or with those predicted from the structure of the inhibitor. Most of the deviations observed could be explained satisfactorily by such factors as solubility or changes in conditions under which the run was made. Reasonable values for film resistances were obtained also.

It was concluded this instrument was useful for classification of water-soluble inhibitors which demonstrate distinct behavior effects.

Corrosion of Centrifugal Gas Compressor Phosphor Bronze Oil-Sealing Sleeves by Edward C. Greco, United Gas Corp.

EDWARD C. GRECO—A native of Louisiana, Mr. Greco is Supervisor of the Water Treatment and Corrosion Chemistry Section, Research Dept., United Gas Corp. He has had 15 years' experience in corrosion work and is vice-chairman of Technical Practices Committee 1 on Corrosion of Oil and Gas Well Equipment and chairman of the Natural Gasoline Association of America's Corrosion Committee. He has been chief explosive chemist for U. S. Army ordnance and special chemist, Development, E. I. DuPont de Nemours & Co., Explosives Division.

Abstract

An increased number of failures of phosphor bronze oil-sealing sleeves in centrifugal compressors has been observed in certain gas pipeline compressor sta-

(Continued on Page 12)

All-Day Committee Meetings Planned For Opening Oct. 7

Thirteen technical papers, a Pipe Line Corrosion Forum and an Oil and Gas Transportation Round Table discussion are included in the technical program prepared for the South Central Region's 1953 annual meeting at Tulsa, October 7-9 inclusive. An open meeting of Technical Practices Subcommittee 1 H on Corrosion of Oil String Casing also is scheduled and several other technical committees will meet. The technical papers cover petroleum inhibitors, hydrogen sulfide corrosion mechanism, cathodic protection of underground pipe lines, three papers on corrosion in processing plants and others.

The tentative schedule was given as follows by W. H. Stewart, program chairman:

Wednesday, Oct. 7

Meetings of the following NACE technical committees have been scheduled.

TP-1 on Corrosion of Oil and Gas Well Equipment.

TP-6B on Protective Coatings for Resistance to Atmospheric Corrosion.

TP-8A on Corrosion by Gulf Coast Cooling Waters.

TP-14A on Electrical Holiday Inspection of Coatings.

TP-18A on Internal Sour Crude Corrosion of Pipe Lines and Tanks.

Oil and Gas Production Symposium, Thursday, Oct. 8—Morning

9-9:40 am—Evaluation of Inhibitors for Gas Lift Wells by D. A. Shock and J. D. Sudbury, Continental Oil Co., Ponca City, Okla.

(Continued on Page 12)

Authors and Abstracts–

(Continued From Page 11)

tions. Failures occurred with greater regularity and frequency when steel wire-brush pipeline scrapers were substituted for the less aggressive rubber-bladed scrapers.

Laboratory studies have shown conclusively that the failures result from the action of iron sulfide particles which originate in the pipeline and have contaminated the circulating seal oil. These solid corrosion products of hydrogen sulfide and iron oxide are attracted to and adhere to the copper bearing oil-sealing sleeves. The iron sulfide initiates and maintains a high corrosion rate with the formation of a thick (7 to 24 mils) copper sulfide scale. The copper sulfide scale plugs the lubrication channels of the oil sealing sleeves and failure follows.

Development of a mechanite oil-sealing sleeve has solved the problem.

Gasket Surface Corrosion by E. V. Kunkel, Celanese Corp. of America, Bishop, Texas.

E. V. KUNKEL—A graduate of the University of Texas in chemical engineering, Mr. Kunkel has worked for Gates Rubber Company, Denver, and came to work for Celanese Corp. of America, Bishop, in 1945. Shortly after starting with Celanese Mr. Kunkel began work with the Inspection and Corrosion Sections in the Plant Engineering Dept. In 1951 he was made Section Leader in charge of corrosion work and in 1953 was made Maintenance Engineering Group Leader, which includes all inspection work as well as maintenance engineering.

Abstract

An illustrated resume of research results on the variations of corrosion of stainless steels with various gasket materials is presented. Slides showing test equipment and methods and test results are shown and the remarkable variation in corrosive attack is discussed. An explanation of the theory of the corrosion encountered and reasons for the variations in effect are given. Methods of avoiding or mitigating corrosion of this kind are discussed also.

Study of the Factors Affecting Heat Resistant Coatings by J. E. Rench, Napko Paint and Varnish Works, Houston.

Abstract

Rench

Specifications are given for the pipe stand apparatus and approved procedure for testing and evaluating heat resistant coatings is stated. Studies on pigment volume concentration, pigmentation, vehicle solids and film thickness and their relationship to heat resistance and durability are reported. Most satisfactory coating found in the investigation was a silicone zinc dust-zinc oxide coating with a relatively high PVC.

Informality to Prevail At Non-Technical Events

Informality will prevail at the non-technical activities scheduled during the South Central Region meeting at Tulsa October 7-9.

A buffet and variety show will be the principal event this year instead of a banquet. Industry suppliers will underwrite this affair as well as the annual fellowship hour.

Entertainment will be provided every day for the ladies. This includes a style show, luncheon, visits to Philbrook and Gilcrease art centers and in the evenings, participation in the fellowship hour and buffet.

Many also may want to attend the Tulsa State Fair and Livestock Exposition which will be underway that week.

South Texas AIChE to Meet in Galveston

South Texas Section, American Institute of Chemical Engineers will hold its Eighth Annual Technical Session, at Galveston, Texas, on October 16. Sessions are planned on industrial organic chemistry, economics and cost estimating, general and student.

All-Day Committee–

(Continued From Page 11)

9:40-10:20 am—Use of a Pearson Bridge for Evaluating Corrosion Inhibitors by Norman Hackerman and B. L. Cross, University of Texas, Austin.

10:20-11 am—Electrochemical Studies of the Hydrogen Sulfide Corrosion Mechanism by Scott Ewing, Carter Oil Co., Tulsa.

11-12 noon—Discussion.

Pipe Line Corrosion Symposium, Thursday, Oct. 8 (Concurrent Sessions)

9-12 noon—Pipe Line Corrosion Forum.

9-9:40 am—Cathodic Protection of Bare

(Continued on Page 13)

NEW PRODUCTS —Materials—Service—Literature

Tetrafluorethylene resin coated glass fabrics are described in a new technical bulletin available from DuPont Co., Fabrics Div., 350 Fifth Ave., New York, N. Y.

•

Welds are inspected by means of gamma rays emitted by a special device designed to run through pipe lines by Isotope Products Ltd., Box 127 Oakville, Ont. A film is wrapped about the weld in the pipe line and the device is started through the pipe. A special braking device, triggered by a low-curie radiation source carried outside the pipe, stops the machine at the exact place inside the weld which permits the gamma rays to penetrate the welded area and make a 360-degree photograph of it. Another device for smaller pipe permits photographing 180 degrees of a weld at one exposure from the outside.

•

Resiment, a low porosity furane resin cement used as a mortar for acid brick or tile will withstand temperatures up to 375 degrees F. It is a product of Delrac Corp., Watertown, N. Y.

•

Ten Basic Types of industrial filtration equipment are described in Bulletin A-943 available from U. S. Hoffman Machinery Corp., Industrial Filtration Division, Thompson Rd., Syracuse 6, N. Y.

Air-Cooled Selenium rectifiers are available from Holcombe & Stearns, Inc., First National Bank Bldg., Shreveport. Manufactured in the company's own shops, they include interchangeable stacks, large knurled knobs for easy voltage adjustment and sturdy transformer taps. The aluminum cases permit access from 3 sides and a plexiglass window permits meter reading without opening the case.

(Continued on Page 15)

All-Day Committee—

(Continued From Page 12)

Pipe Lines in High Resistance Soils by R. C. Martin, Plantation Pipe Line Co., Atlanta, Ga.

9:40-10:20 am—Economics of Pipe Line Corrosion Mitigation by L. G. Sharpe, Humble Pipe Line Co., Houston.

10:20-11 am—Cathodic Protection of Plant Yards with Distributed Anode Systems by B. J. Whitley, Jr., Tennessee Gas Transmission Co., Houston.

11-12 noon—Discussions.

Thursday, Oct. 8—Afternoon

2-2:40 pm—Paper, title unavailable.

2:40-3:20 pm—Paper by Art Erickson, People's Natural Gas Co., Pittsburgh, Pa.

3:20 pm—Discussions.

Processing Plant Symposium, Thursday, Oct. 8 (Concurrent Session)

2-2:40 pm—A Study of Factors Affecting Heat Resistant Coatings by Joe Rench, Napko Paint & Varnish Works, Houston.

2:40-3:30 pm—Corrosion of Centrifugal Gas Compressor Phosphor Bronze Oil-Sealing Sleeves by Edward C. Greco, United Gas Corp., Shreveport.

3:20-4 pm—Gasket Surface Corrosion by E. V. Kunkel, Celanese Corp. of America, Bishop, Texas.

4 pm—Discussion.

Oil and Gas Production Symposium, W. F. Oxford, Jr., Chairman, Friday, October 9—Morning

9-9:40 am—Evaluation of Ammonia for Control of Hydrogen Sulfide Vapor Zone Corrosion by A. C. Broyles and R. C. Sommer, Carter Oil Co., Tulsa.

9:40-10:20 am—Theoretical and Practical Aspects of Using Ammonia Injection to Prevent Casing Corrosion by H. L. Bilhartz, H. E. Greenwell, and Rado Loncaric, Atlantic Refining Co., Dallas.

10:20-12 noon—Discussions.

Friday, Oct. 9 (Concurrent Session)

2-4 pm—Oil and Gas Transportation Round Table.

2-4 pm—Technical Practices Subcommittee 1H on Corrosion of Oil String Casing.

2-4 pm—Technical Practices Subcommittee 6E on Protective Coatings in Petroleum Production.

NEW PRODUCTS

(Continued From Page 13)

Thermo-Cote D, an ethylcellulose strippable coating compounded by Plastics Division, Ernst Bischoff Co., Inc., Ivorytown, Conn., is applied by the hot dip process. It is recommended to prevent corrosion and abrasion of metal parts and tools in storage.

•

Buna N Hard Rubber pumps are being offered by the Vanton Pump Corp., Empire State Bldg., New York City. The Vanton pump is designed for pumping highly corrosive materials. Temperatures up to 225 degrees F are withstood satisfactorily by the new pump block, the manufacturers claim.

•

Custom Molded thermoplastic, Teflon and synthetic rubber O-rings and hydraulic packings manufactured by Stillman Rubber Co., 581 Marilyn Ave., Culver City, Cal., are described in a 24-page catalog available on request.

•

Protection of Steel Piling, casing, christmas trees and other metals exposed in the tidal zone against corrosion is claimed through the use of its "Tidal Zone Protective Jacket" by Corrosion Rectifying Co., 1506 Zora St., Houston 24, Texas. The method involves fixing a jacket about the exposed metal in the tidal zone range with Monel straps and pouring into the space between the jacket and the metal to be protected an inhibitive grease, mastic or cement. The jacket itself is made of Fiberglas reinforced polyester plastic. Because of this material's inertness to corrosives and high dielectric strength, substantial protection against corrosion is claimed. Jackets can be fabricated for special installations.

•

Spiral Teflon Backup Rings designed to protect rubber o-ring seals indefinitely from extrusion, deterioration or loss of efficiency are available from W. S. Shamban & Co., 11617 W. Jefferson Blvd., Culver City, Cal.

•

Powder Metallizing methods are used by Bondwel, Inc., 1401 Middle Harbor Road, Oakland, Cal., in spraying coatings of Thiokol, other plastics, zinc and aluminum to exterior and interior surfaces to prevent corrosion. An illustrated bulletin describing the company's services is available on request.

•

Hard-facing electrodes and rods for wear correction and corrosion prevention applications are described in a 12-page bulletin available from Alloy Rods Co., York, Pa.

•

Steam-Blaster, a flat nozzle with a patented center blade reduces eddy turbulence at the orifice and creates a pressure differential between two flat planes of steam, American Nozzle Corp., New York, claims. More efficient cleaning and stripping as a result of this is claimed.

•

A 20,000-square-foot new plant for the production of magnesium is scheduled to be built at 7500 East 41st St., Tulsa, by Standard Magnesium Corp. The firm will have a capacity of 4,000,000 pounds of magnesium yearly in its new location. Distribution at present is to the aircraft industry, oil industry and for alloying purposes.

•

Vacuum Impregnation, a 24-page brochure describing applications and equipment for this process, is available from F. J. Stokes Machine Co., 5500 Tabor Road, Philadelphia 20, Pa.

Zirconium is now being produced by arc dissociation of halides in a new process developed by National Research Corp., Cambridge, Mass., for the U. S. Atomic Energy Commission. The process may be commercially interesting for the production of special grades of zirconium and titanium but not for volume production of these metals. Animal feed or food additives may be produced from sewage if studies by Dr. J. B. Lackey, University of Florida, Gainesville, are successful. Scientific conference on solar energy will be held Sept. 12-14 at University of Wisconsin, Madison. A technique for taking three dimensional photographs of microscope specimens has been developed by Roy Pence, University of California, Los Angeles. These items from Industrial Research Newsletter, Armour Foundation.

POSITIONS WANTED and AVAILABLE

- Active and Junior NACE members may run without charge two consecutive advertisements annually under this heading, not over 35 words set in 8 point text type.
- Firms seeking employees, regardless of NACE membership, may run an advertisement of the same specifications indefinitely.
- Advertisements to other specifications will be charged for at standard rates.

Positions Available

Corrosion Engineers. Positions available for graduate electrical engineers or equal. Previous field and design experience in corrosion mitigation systems required. Extensive travel involved. Salary open. The Hinchman Corp., Engineers, Francis Palms Bldg., Detroit 1, Mich.

•

Sales Representatives for DEL Protective Coatings. Protected territories available to qualified individuals or companies. No objection to carrying non-competitive lines. Write David E. Long Corp., 220 East 42nd St., New York 17, N. Y.

Positions Wanted

Chemical Engineer (BS), member NACE, desires New England location. Age 36. 8 years' experience process engineering, corrosion, instrumentation. Currently employed Mid-west. CORROSION, Box 53-13.

PERSONALS

Ralph D. Parker has been elected president of Canadian Nickel Co., Ltd.

Robert E. Zinn has been appointed professor of chemical engineering at Northwestern University Technological Institute.

A. C. Hillman has been named a special consultant by Kelite Products, Inc.

C. Donald Steinwedel of Bristol, Va., has been named sales representative of The Carpenter Steel Company's Alloy Tube Division for five Southeastern states.

Frank J. Bonner has been named Zone Manager, Pacific Industrial Sales, for The Sherwin-Williams Co. His headquarters will be at Oakland, Cal.

James F. McKeon and **Warren J. Clark** have been promoted to sales representatives for industrial resins by Monsanto Chemical Company's plastics division. They are located at Cincinnati and St. Louis, respectively.

Ray N. Griffin has been named vice-president in charge of sales and advertising for Bart-Messing Corp. and associated companies. He was formerly treasurer. A Texan he is a graduate of Texas Christian University. **William A. Hopkins** has been appointed vice-president in charge of manufacturing by Bart Manufacturing Co. He formerly was sales manager for the company's associate, Bart-Messing Corp.

Richard F. Puffer has been named assistant general sales manager; Allen W. Rockwell, manager of the Waterbury Branch and Robert R. Vance will succeed Mr. Rockwell as works manager at the Waterbury Branch, American Brass Co. reports.

Arthur R. Borden, for 12 years manager of the Hagan Corp., Detroit branch, died at his home in Detroit July 6.

American Cast Iron Pipe Co., Birmingham, Ala., announces the following personnel changes: **A. J. Herrmann** has been elected vice-president in charge of sales and secretary of the firm. He succeeds **Lester Long,** who retired July 12 after 38 years continuous service. **J. W. MacKay** has been appointed assistant general sales manager succeeding Mr. Herrmann.

John H. Caldwell has joined S. D. Day Company as sales engineer. He formerly was corrosion engineer with Glenn Martin Aircraft Corp.

C. E. Ford has been named manager of Chemical Carbon Sales Department of National Carbon Co., a division of Union Carbide & Carbon Corp.

R. W. Henze will head the new direct sales office of The Duriron Company, Inc., at Needham, Mass.

Albert H. Bagenstose has been named Eastern regional manager and **John J. Miller,** Midwestern regional manager by Insul-Mastic Corp. of America, Pittsburgh.

Corrosion Abstracts

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1. GENERAL

1.2 Importance

1.22, 5.23, 8.93

Economics of Rectifier Installation for Cathodic Protection of a Bare Pipe Line. D. C. Glass. *Corrosion* **7**, 322-326 (1951) Oct.

A report on 10-yrs. operating experience with rectifiers for cathodic protection of a 10-in. crude oil pipe line in the Texas-Gulf Coast area. Describes design of the system and gives performance data on rectifiers, experience with ground beds, current requirements to maintain protection, bonding procedures with parallel and/or crossing foreign structures, and leak frequency. An economic study is made of the system based upon investment charges, operating and maintenance costs, and actual power costs. Tables and discussion.

1.2.2, 5.4.5

1. Rust-Protective Painting is of National Importance. 2. Further Remarks on Rust Protection in the National Economy. *Ind.-Lack Betrieb*, **19**, Nos. 2, 3; 19-20, 39 (1951).

1. Despite increasing lead and linseed-oil shortage, it is still necessary to produce anti-corrosive paints of high protective value. Lead can be saved to some extent by replacement with extender pigments. Numerous natural and

PHOTOPRINTS and/or MICROFILM COPIES

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CARNEGIE LIBRARY OF PITTSBURGH, 4400 Forbes St., Pittsburgh 13, Pa.

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LIBRARY OF CONGRESS Washington, D. C.

JOHN CRERAR LIBRARY 86 East Randolph St., Chicago 1, Ill.

Persons who wish to secure copies of articles when original sources are unavailable, may apply directly to any of the above for copies. Full reference information should accompany request. The National Association of Corrosion Engineers offers no warranty of any nature concerning these sources, and publishes the names for information only.

NACE will NOT accept orders for photoprint or microfilm copies of material not published by the association.

CODE OF AGENCIES SUPPLYING CORROSION ABSTRACTS

Neither NACE nor the sources listed below furnish reprint copies.

AER—Aeronautical Engineering Review, Institute of Aeronautical Sciences, Inc. 2 East 64th St., New York 21, N. Y.

ALL—The Abstract Bulletin, Aluminum Laboratories, Ltd. P. O. Box 84, Kingston, Ontario.

AWWA—Journal, American Water Works Association, Amer. Water Works Assoc., 521 Fifth Ave., New York 17, N. Y.

BL—Current Technical Literature, Bell Telephone Laboratories, Inc., Murray Hill, N. J.

BTR—Battelle Technical Review, Battelle Memorial Institute, 505 King Ave., Columbus 1, Ohio.

BNF—Bulletin; British Non-Ferrous Metals Research Association. 81-91 Euston St., London NW 1, England.

CALCO—Calco Chemical Division, American Cyanamid Corp. Bound Brook, New Jersey.

CE—Chemical Engineering, McGraw Hill Publishing Co. 330 W. 42nd St., New York 18, N. Y.

CEC—Consolidated Edison Co. of New York, Inc. 4 Irving Place, New York 3, New York.

EL—Electroplating. 83/85 Udney Park Road, Teddington, Middlesex, England.

EW—Electrical World, McGraw-Hill Publishing Co. 330 W. 42nd St., New York 18, N. Y.

GPC—General Petroleum Corp. of California. 2525 East 37th St., Los Angeles 11, Calif.

INCO—The International Nickel Co., Inc. 67 Wall Street, New York 5, New York.

IP—Institute of Petroleum. 26 Portland Place, London W#1, England.

JSPS—Japan Society for the Promotion of Science, Address: Mr. Hayata Shigeno, Secretary, Committee of Preventing Corrosion, c/o Government Chemical Industrial Research Institute, 1-Chrome Nakameguro, Meguro-ku, Tokyo, Japan.

MA—Metallurgical Abstracts, Institute of Metals, London, England. 4 Grosvenor Gardens, London SW 1, England.

MI—Metallurgia Italian. Associazone Italiana di Metallurgia. Via S. Paola, 10, Milano, Italia.

MR—Metals Review, American Society of Metals. 7301 Euclid Ave., Cleveland 3, Ohio.

NALCO—National Aluminate Corp. 6216 West 66th Place, Chicago 38, Illinois.

NBS—National Bureau of Standards. Supt. of Documents, U. S. Gov't Printing Office, Washington 25, D. C.

NSA—Nuclear Science Abstracts. United States Atomic Energy Commission, Technical Information Division, Oak Ridge, Tenn.

PDA—Prevention Deterioration Abstracts. National Research Council, 2101 Constitution Ave., Washington 25, D. C.

RA—Refrigeration Abstracts, American Society of Refrigeration Engineers. 40 West 40th St., New York 18, N. Y.

RM—Revue de Metallurgie, Paris, France. 5 Cite Pigalle, Paris (9e), France.

RPI—Review of Current Literature Relating to the Paint, Colour, Varnish and Allied Industries, Research Association of British Paint, Colour & Varnish Manufacturers, London. Waldegrave Rd., Teddington, Middlesex.

SE—Stahl Und Eisen, Verlag Stahleisen, M. B. H., Dusseldorf, August-Thyssen Str. 1. Postscheck Koln 4110, (22a) Dusseldorf, Germany.

TIME—Transactions of Institute of Marine Engineers. 85 The Minories, London EC 3, England.

UOP—Universal Oil Products. 310 South Michigan Ave., Chicago, Illinois.

ZDA—Zinc Development Association. Lincoln House, Turl Street, Oxford, England.

synthetic media are suggested as alternatives to linseed oil.

2. A previous report, that up to 80% replacement of red lead in paints does not impair protection against rust in interior decoration, may be a false economy in view of the greater need for exterior rust protection where previous experience has shown only 40% adulteration is permissible. The German Federal State Railways now permit 40% adulteration of red lead with barytes but not with red iron oxide.—RPI.

1.3 Reviews

1.3, 6.6.4, 8.8.1

Carbon and Graphite. W. M. Gaylord, *Industrial and Engineering Chemistry*, **43**, 2199-2202 (1951) Oct.

Surveys the literature on the developments and applications of carbon and graphite in the chemical industries. 53 references.—BLR.

2. TESTING

2.2 On Location Tests

2.2.5, 5.4.5

Subsidiary Paint Tests at Birmingham: Final Report. J. C. Hudson. Paper MG/EA/18/50 of Protective Coatings Sub-Committee of Metallurgy Div., Brit. Iron Steel Research Assoc. *J. Iron Steel Inst.*, **169**, Pt. 2, 153-156 (1951) Oct.

Exposure test over 15 years confirmed that surface preparation is the most single factor contributing to successful protection of iron and steel by means of paint, against atmospheric corrosion. The average life of 2-coat painting schemes was 6 times greater on a pickled surface than on a weathered and wire-brushed one. The best of the painting schemes tested—2 coats of micaceous iron ore paint—protected pickled wrought iron perfectly for the whole 15 years. Even better results should be obtained by using a red lead priming paint under a finishing coat of micaceous iron ore paint. Heating a weathered surface so as to dehydrate the rust, improved the performance of painting schemes, but this was still greatly inferior to that on the descaled and unrusted surface obtained by pickling. Tables give the results of the exposure tests made.—INCO.

2.3 Laboratory Methods and Tests

2.3.2, 5.4.5

Accelerated Testing. H. Hesse. *Farbe u. Lack*, **57**, No. 2, 68-69 (1951).

A short discussion on the value of accelerated testing methods. These methods are suitable for rough assessment of simple properties of a paint system or for assessing the effect of changes in composition of a given system, but should not be used to forecast length of service in actual exposure conditions. It is recommended that systems of low binder content, and rubber paints, be allowed three days after painting before submission to test; for systems of high binder content, the period should be 6 days.—RPI.

2.3.7, 6.3.11, 3.2.3

Measurement of the Oxide Film on Platinum. II (In German). Heribert Grubitsch and Fritz Todt. *Werkstoffe und Korrosion*, **2**, 415-416 (1951) Nov.

On the basis of previous work, a theory of the mechanism of oxide formation on platinum is developed. The various results of Todt and of Grubitsch, especially the time dependence of oxygen charging of a platinum surface in an oxygen-containing electrolyte, can be explained on the basis of the above theory.—BLR.

2.3.9

Radioactive Current Source. *Electronics*, **25**, 212-214 (1952) Jan.

Radioactivity can be used as a source of electric energy (at low levels) through the use of an "atomic battery" recently developed by the Ohmart Company of Cincinnati, Ohio. The conversion of radioactive energy to electrical energy is obtained by a cell made of two dissimilar materials separated by filling gas. Uses in corrosion measurement, analysis of alloys, gas analysis and measurement of vacuum, pressure, and temperature are indicated.—BLR.

2.3.9

Specific Surface Area of Metal Powders. I. M. Fedorchenko. *Bull. Acad. Sci. U.R.S.S.* [Izvest. Akad. Nauk (S.S.S.R.) Otdel. Tekh.], **1951**, 411-418.

The specific surface area of iron, copper and nickel prepared by different methods and before and after annealing were measured by a gas-permeability method.—RPI.

2.3.9

Useful Etchants for Electron Metallography. W. J. Grube. General Motors Corp. *J. Metals* (Trans. AIME), **3**, No. 12, 1171-1173 (1951) Dec.

Results of the use of various etchants on typical metallographic specimens are shown. A suitable etchant for electron metallography must in all cases exhibit a preferential attack upon each of the microconstituents present sufficient to result in a difference in surface elevation. A photomicrograph is shown of a vacuum-cathodic etch which develops the structure of the primary carbide in Vitallium. Photomicrographs and five references are included.—INCO.

2.3.9, 2.3.7

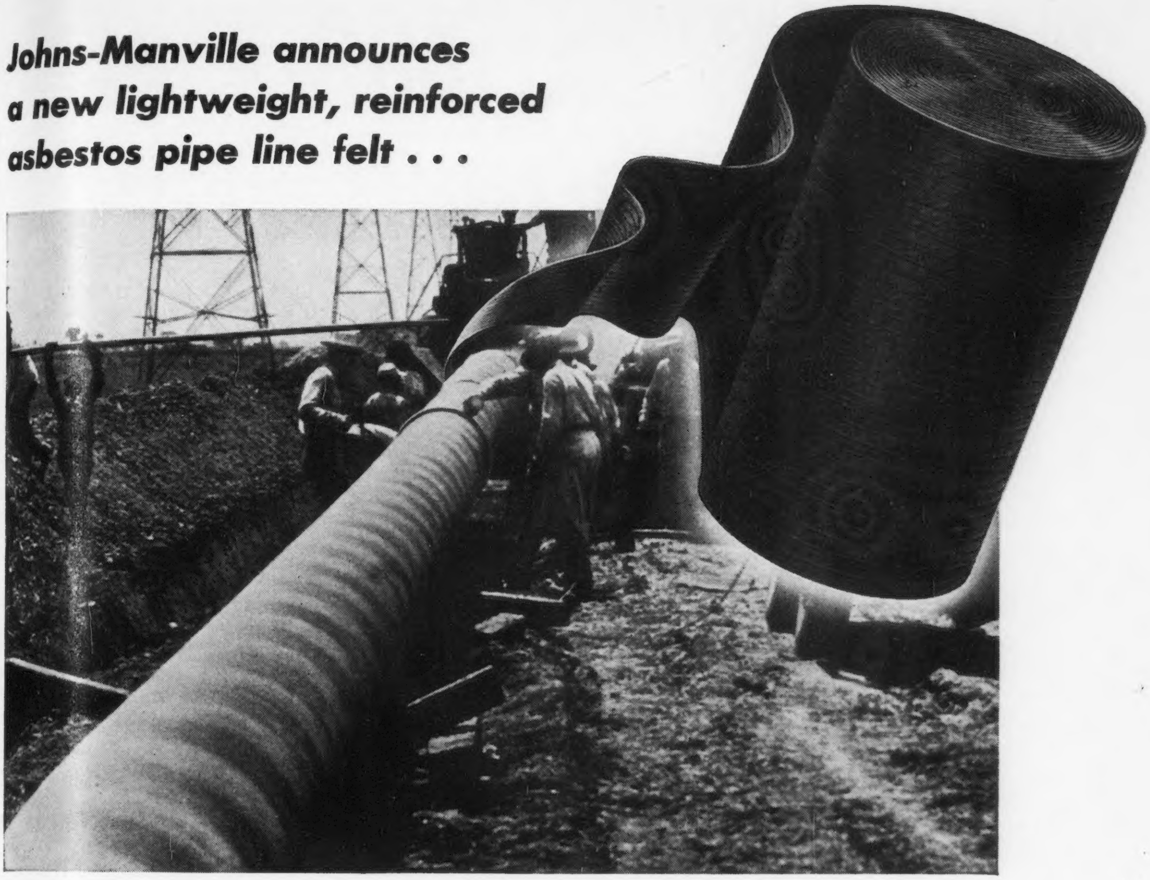
Study of a Method for Measuring the Thickness of Non-Magnetic Layers on Steel. (In Japanese). Osamu Ito. *J. Mechanical Laboratory* (Japan), **5**, 153-156 (1951) Aug.

The method consists of measuring the force required to separate a magnet energized by a.c. from the surface of a coated steel article, by use of a self-compensating magnetic balance. Thickness of nonmagnetic coatings and platings on a steel base can be easily measured without destruction. Graphs and tables.—MR.

2.3.9, 2.4.3, 6.2.2

Evaluation of Soundness of Cast Iron. Institute of British Foundrymen. 1951, 22 pages.

Reports on experimental evaluation of various methods for the above. Includes results obtained by radiography, ultrasonic flow detection, electrical and magnetic methods, density determination, pressure testing, and other methods. Gives general conclusions and recommendations. Graphs, tables, diagrams and illustrations.—BLR.



2.3.9, 3.7.4

Nuclear-Reaction Radiography. MATS HILLERT. *Nature,* **168,** No. 4262, 39-40 (1951).

The method is similar to autoradiography, but may be used when the material to be detected is not itself radioactive. Secondary particles generated in the material by neutron irradiation are recorded on a photographic emulsion placed in contact with the material. α-particles generated in the boron of the iron-boron alloy revealed the distribution of boron quite accurately. The method is particularly useful when the element to be detected has no radio-active isotope, and when this element has a much higher probability of reacting with the incident neutrons than any other element present.—MA.

2.3.9, 3.7.4, 6.3.10

Radioactive Isotopes in Metallurgy. *Intern. Chem. Eng. & Process Inds.,* **32,** No. 8, 381-382, 385 (1951) Aug.

Studies in which radioactive isotopes have been used. Diffusion and self-diffusion, properties of alloys, corrosion effects, metal cleaning, friction studies, electroplating and factory-scale investigations are discussed. Radioactive tungsten (W185) has been used to determine the location of tungsten in a 70 nickel, 25 chromium, 5 tungsten alloy.—INCO.

2.3.9, 8.9.5, 2.4.3

Gamma-Radiography in Shipbuilding and Engineering. J. D. HISLOP. *Trans. Inst. Marine Engrs.,* **63,** No. 5, 83-96 (1951). *Engineering* **171,** No. 4442, 327-330 (1951).

Hislop defines the terminology employed in radiography and indicates the relative activities and "half-value" periods of the various γ-ray sources available to industry. The factors governing the correct choice of source are dis-

cussed, and techniques employed for the examination of typical castings are described. Hislop compares the merits of methods applying γ-ray sources with those using X-rays and outlines the limitations of both techniques.—MA.

2.4 Instrumentation

2.4.2, 2.3.9
New Technique in Corrosion Study. *J. Electrochem. Soc.*, **98**, No. 9, 125C, (1951) Sept.

A new technique for the study of corrosion processes has been developed at the Armour Research Foundation in Chicago. The method is called the "rotogenerative technique" and employs a rotating cylindrical corrosion specimen scanned by a stationary reference electrode. The signal sensed by the reference electrode is amplified and presented on an oscilloscope. The resulting pattern represents the voltage distribution across the specimen surface.—ALL.

2.4.2, 3.5.8
A Tension-Impact Machine for Stress-Corrosion Experiments. W. W. Johnstone. Commonwealth Australia, Dept. Supply Aeronautical Research Lab., Structures and Materials Note, No. 195, 1951, 7 pp.

The machine described was designed to study the behavior of surface films arising from the corrosion of aluminum. Steady, impact, or cyclic axial loading can be given in turn by two tension springs, one for minimum and the other for maximum load. The change from minimum to maximum load occupies < 0.2 seconds.

Operation of a number of machines at the same frequency, but at different load ranges, is possible by connecting them all to one solenoid valve energized by an electric timing controller.—MA.

2.4.3
Nondestructive Crack-Detection Method Using Radio-Active Indicators. (In German). J. Kaindl and A. Mathiaschitz. *Werkstoffe u .Korrosion*, **2**, 368-369 (1951) Oct.

Describes above method and illustrates typical results on different steels by means of micrographs and macrographs.—BLR.

2.4.3, 1.2.5
Observations on the Practice of Gamma-Ray Inspection. H. Gerbeaux and M. Evrard. *Metaux: Corrosion-Industries*, **26**, No. 308, 159-165 (1951).

A description of equipment and personnel protection when using artificial radioactive sources in examination for material defects. Examples of application are given.—MA.

2.4.3, 2.3.9
A Non-Destruction X-Ray Method for the Determination of the Thickness of Surface Layers. P. Gay and P. B. Hirsch. *Brit. J. Applied Physics*, **2**, No. 8, 218-222 (1951) Aug.

Method suitable for all layers with reflection coefficients different from that of the matrix. No blank experiment is required and the method is applicable to single crystal bases. Theory and procedure.—BNF.

2.4.3, 2.3.9, 1.6
The Non-Destructive Testing of Metals. R. F. Hanstock. Chief Physicist, High Duty Alloys, Ltd., Slough, Bucks. Institute of Metals Monograph and Report Series No. 10. The Institute of Metals, 4 Grosvenor Gardens, London, S. W. I. 1951. 164 pp., 71 illustrations. Price 21s., post free.

In this monograph, Dr. Hanstock has made a comprehensive survey of the various methods that are available for the non-destructive testing of metals, ranging from liquid-penetration methods of crack detection to the use of X-ray diffraction for the determination of grain-size and orientation and for the measurement of internal stresses. Special attention is devoted to damping-capacity measurements as a means of non-destructive testing.

Throughout, emphasis is laid on the physical bases of the methods described,

with specific examples of their application in many cases. The use of the book is facilitated by an appendix in which are given, in tabular form, the properties that may be assessed by non-destructive means, the various methods applicable in each case, and brief comments on their suitability and limitations.—TIME.

2.4.3, 2.4.2

Non-Destructive Testing of Tungsten and Molybdenum Wires with the Drahtrisskawimeter (Wire-Flaw-Kawimeter). (In German). E. Gromodka. *Metall,* **5,** Nos. 15-16, 335-336 (1951) Aug.

Brief report of successful use of this instrument in detecting both internal and surface flaws. The instrument is not described but is presumably a variation of the Durokawimeter.—BNF.

3. CHARACTERISTIC CORROSION PHENOMENA

3.2 Forms

3.2.2, 6.2.4

Effect of Hydrogen on the Properties of Low Alloy Steels. J. D. Hobson and C. Sykes. *J. Iron Steel Inst.,* **169,** Pt. 3, 209-220 (1951) Nov.; *Metal Progress,* **61,** 114+ (1952) Mar.

Method is described by which hydrogen is introduced into steel specimens by heating them in the gas at high pressures. The deleterious effect of hydrogen on the ductility of low-alloy steels, containing 0.10-3.69 nickel was investigated and shown to be reproducible, provided that their heat-treatment is also considered. Hydrogen additions have the same effect whether carried out by electrolysis or by the high-pressure technique. Graphs show hydrogen embrittlement comparisons of various nickel steels, and tables give the analyses of the steels used and the effect of hydrogen on the impact values of 2½ nickel-chromium-molybdenum steel. 12 references.—INCO.

3.2.2, 6.2.5, 3.7.1, 3.5.9

885° F. Embrittlement of the Ferritic Chromium-Iron Alloys. J. J. Heger. U. S. Steel Co. *Metal Progress,* **60,** No. 2, 55-61 (1951) Aug.

The 885° F. embrittlement of the ferritic stainless steels is characterized by an increase in hardness, tensile strength, and yield strength and by a decrease in ductility and impact strength. Changes in electrical resistance density, magnetic properties and corrosion resistance also occur. These changes in mechanical and physical properties occur after the steels have been heated in the temperature range of 700-1000° F., and have been observed in tests made at room temperature and tests made at the embrittling temperature. Neither additions of alloying elements (chromium, carbon, titanium, niobium, molybdenum, manganese, silicon, nitrogen, nickel, phosphorus), variations in heat treatment, nor elimination of impurities have prevented these gradual changes in the hot alloy. For pure iron-chromium alloys, the embrittlement is believed to be caused by the precipitation of sigma phase. Graphs, tables and 15 references are given.—INCO.

3.2.2, 6.4.1

Mechanism of Intergranular and Stress Corrosion of Aluminum-Magnesium and Aluminum-Zinc-Magnesium Alloys. Pierre Jacquet. *Compt. rend.,* **233,** 871-873 (1951) Oct.

When aluminum-base alloys, such as AG 7 (aluminum-magnesium) and Zicral (aluminum-magnesium-zinc), are immersed in neutral sodium chloride solution, they suffer deep fissuration as the result of intergranular attack which continues even after the alloy has been rinsed and immersed in cold water. The finer its grain structure, the more intense is the corrosive attack. Zicral is very susceptible to intergranular corrosion when tempered at 465° C. The same corrosion phenomena are also observed on a sensitized sample when it is coupled with a less susceptible specimen of the same alloy.

The mechanism of intercrystalline corrosion presumably involves a chemical chain reaction in which the activated anodic areas of the alloy, usually minute imperfections and regions strained by work hardening, are attacked by chloride ions with evolution of hydrogen and formation of aluminum chloride. Hydrolysis of this compound yields a deposit of aluminum hydroxide (gelatinous alumina) and free hydrochloric acid attacks additional anodic areas and thus renews the cycle. In this manner, minute anodic crazings, pits, or fissures are enlarged and deepened.

Increasing the pH of the medium by addition of sodium hydroxide does not inhibit this type of corrosion once deep pits and fissures have been formed, because the hydroxide cannot reach these areas where hydrochloric acid is continuously formed. The corrosion is

slowed down and stopped by cathodic polarization and by the aluminum hydroxide deposit; however, mechanical stresses disrupt this protective layer and expose and reactivate the alloy surface. In the absence of subsequent deformation, annealing at 130° C., prevents intergranular corrosion of aluminum-zinc-magnesium alloys, because this treatment shifts their electropotential to more positive values.

3.2.2, 6.4.1

Procedures for Determining the Gas Content of Light Metals (Hydrogen in Aluminum Alloys). I.—Principles of the Methods. II.—Routine Procedures. III. —Laboratory Methods. (In German). H. Kostron. *Metall,* **6,** No. 5/6, 115-123 (1952) Mar.

Part I. Solution equilibrium and blister formation. Part II. Qualitative methods (measurement of density of castings and comparison of the surface before and during solidification, vacuum casting test, and observation of blisters formed on heating solid metal) and quantitative (Dardel's vacuum) methods. Part III. The "hot extraction" method (which is considered the best), degassing by ionic bombardent, and chemical methods (solution in carbon disulphide and bromine, or flushing with chlorine). 36 references.—BNF.

3.2.2, 8.4.3

Graphitization of Steel. A. M. Hall

AND H. M. BANTA. *Oil and Gas Journal*, **50,** 101-102, 105-106 (1951) Oct. 11.

Graphitization has caused several spectacular failures or near failures in steam lines, which have been thoroughly investigated during the past 8 years. More recently, it was found that the same phenomenon may be present in petroleum refining, especially in catalytic cracking. Briefly explains the phenomenon of graphitization and outlines available information which is applicable to the petroleum refining industry.—BLR.

3.2.3, 8.9.3, 3.7.3, 3.5.8

Report on Investigations into the Stress-Corrosion Cracking in Welded Gas Mains. Institution of Gas Engineers (London), Communication 398, 1951, 31 pp.

Studies of the above showed that the cracks are intercrystalline and typical of other examples of stress-corrosion cracking, that they are associated with the welds, that cracking invariably starts from the inside of a main, and that the cracks are frequently associated with irregularities in the weld bead. A hot nitrate-solution test seemed to be satisfactory for determining relative susceptibility of steels to this form of cracking. Micrographs.—BLR.

3.3 Biological Effects

3.3.2,3.3.3, 5.7.7, 1.7.2

Littoral Diatoms of Chichester Harbour with Special Reference to Fouling. N. I. HENDEY. *J. Royal Microscopical Soc.*, 71, Pt. 1, 1-86 (1951).

The diatom is considered as an important element in fouling. Diatoms that occur as fouling are classed as "slime-formers" or "non-slime formers," and are further divided on a basis of *modus vivendi*, without reference to taxonomic affinities. The significance of the "slime" on anti-fouling paint and the alteration of roles played by the diatom and bacterial components are tentatively advanced as a factor that affects the anti-fouling properties of the paint in the sea, by affecting the pH of the slime. Methods for cleaning and preparing material for examination are described. Seasonal distribution charts are appended, and descriptions and citations provided for all diatom species (exclusive of truly planktonic ones) that have been recorded on anti-fouling paint from the Admiralty's exposure sites in Chichester Harbour. Two species, previously unknown to science, are described. A table is given showing the relative resistance of different species of diatom to anti-fouling paints containing cuprous oxide.—RPI.

3.4 Chemical Effects

3.4.6, 6.3.20

The Reaction of Zirconium Metal Surfaces With Oxygen. M. W. MALLETT, H. R. NELSON AND C. A. PAPP. Battelle Memorial Inst. Feb. 25, 1952. 21 pp. (BMI-727).

Oxygen 99.5 to 99.6% pure was dried over magnesium chlorate and successively brought into contact with 29 cylindrical zirconium rods ½ in. in diameter. Each zirconium specimen was maintained at a constant temperature between 600° and 1100°C for the duration of the run. It was found that oxygen reacts with zirco-

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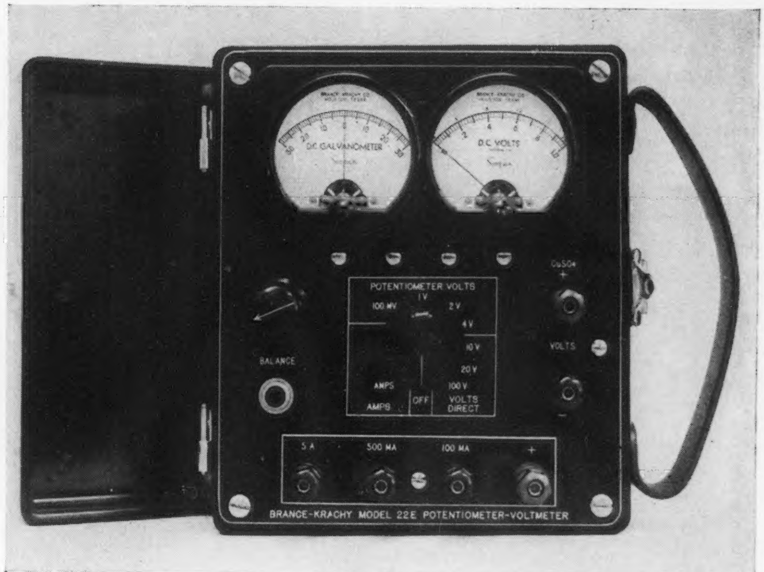

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nium at rates which appear to be close to parabolic (square-root function of time) at 600°C, decrease to a one-fourth-power function of time at 875°C, and increase to parabolic at above 1100°C. This behavior, in contrast to expected parabolic rates, is thought to be brought about by some effect of the transition from alpha to beta zirconium (865° ± 10°C). An empirical equation which expresses this behavior may be written as follows:

$$w = K_1 t^{1/2} + K_2 t^{1/4} + K_3 t^{1/2}$$

$K_1 = 3.11 \times 10^{-1}\ e^{-8000/RT}$ ml/cm²-sec$^{1/2}$,
$K_2 = 2.54 \times 10^{3}\ e^{-21000/RT}$ ml/cm²-sec$^{1/4}$,
$K_3 = 2.09 \times 10^{8}\ e^{-56000/RT}$ ml/cm²-sec$^{1/2}$,
w = oxygen reacted in ml/cm²,
t = time in seconds.

Energies of activation at temperatures in the neighborhood of 300°C (alpha zirconium) and 1500°C (beta zirconium) have been approximated as being 16000 cal/mole and 112000 cal/mole, respectively. Large probable errors in these values make comparisons with other reported values inconclusive. No pressure dependency of the reaction was observed.—NSA.

3.5 Physical and Mechanical Effects

3.5.3, 3.4.6

Influence of Roughness and Oxidation on Wear of Lubricated Sliding Metal Surfaces. C. B. Davs. *Annals of the New York Academy of Science,* **53,** art. 4, 919-935 (1951) June 27.

Measurements were made, at room temperature, of the wear of a flat steel annulus flooded with lubricant and pressing against the lower end of a small vertical cylindrical tungsten-carbide pin. In another apparatus reciprocating motion produced rubbing of silver-copper and mild steel-nickel-chromium steel combinations in oxygen, nitrogen, or air. Effects of surface-active agents and of other chemicals on wear and corrosion were studied. Results are charted, tabulated, and illustrated.—BLR.

3.5.8, 5.3.2, 2.3.4

The Influence of Different Surface Coatings on the Fatigue Strength of Steel. O. Forsman and E. Lundin. Paper before 1st World Metallurgical Congress, Detroit, Oct., 1951. Proc. 1st World Metallurgical Congr., ASM, 1951, 606-612.

Fatigue tests were carried out on a number of steels with and without surface coating of zinc, tin, cadmium, nickel and chromium. The tests were carried out in air, tap water and 3% salt water. In tap water both zinc and cadmium afforded good protection. In 3% salt water only zinc was found to give satisfactory protection. For oil-hardened and annealed shaft steels hot galvanizing was found to reduce the fatigue limit in air to a considerable extent, though the tempering temperature was well above the temperature of zinc bath. Electrolytic zinc coating, on the other hand, had no appreciably reduced effect. Tables and 8 references are given.—INCO.

3.5.9, 6.4.2

Aluminum-Steel Alloy Offers High Resistance to Oxidation and Heat Scale. *Materials and Methods,* **35,** No. 2, 138 (1952) Feb.

The Cambridge Wire Cloth Co., Cambridge, Md., has announced the introduction of Cambriloy-Al, a new material for fabricating woven wire conveyor belts for annealing and decorative lehrs in glass manufacturing plants. It is a specially developed aluminum-steel alloy surfaced wire which is said to offer an extremely high degree of resistance to oxidation and heat scale. When placed in operation, the heat of the lehr produces a hard coating of aluminum oxide on the surface of the wire. The aluminum coating actually alloys with the steel to form an alloy surfaced wire.—ALL.

3.5.8, 2.4.2, 2.3.7

Method and Apparatus for Testing the Resistance of Metals to Stress-Corrosion. E. Gasior. *Prace Glownego Inst. Met.,* **3,** No. 3, 241-250 (In Polish) (1951); *J. Inst. Metals & Metallurgical Abs.,* **19,** No. 7, 546 (1952) Mar.

Constant-load and constant-strain methods of testing the resistance of metals to stress corrosion are reviewed. The former are characterized by rapid fracture of the specimen and small scatter of results. A modification of Brenner's method (Vortrage der Hauptversammlung 1938 Deut. Ges. Metallkunde, 1938, 2?; M.A. **6,** 245), in which a constant bending load is applied to the specimen, has been experimentally compared with Smialowski's method, employing a constant tensile load. Steel specimens of composition 0.1 carbon, 0.41 manganese, 0.15 silicon, 0.12 copper, 0.036 phosphorus, 0.034 aluminum, and 0.025 sulfur were soaked for 30 minutes at 910° C, quenched in water, and subjected to tests in 40% aqueous ammonium nitrate solution, at 90°-100° C. Smialowski's

method requires a smaller amount of tests of shorter duration with loads up to 80% Ultimate Tensile Strength and gives a smaller scatter of results with Brenner's method. It is therefore preferred. 28 references.

5. PREVENTIVE MEASURES

5.2 Cathodic Protection

5.2.1, 6.4.2

On the Cathodic Protection of Aluminium and its Alloys. G. Ito. *Light Metals* (Japan), No. 4, 91-95 (1952) Aug.

The cathodic protective method for aluminum and its alloys from corrosion in various electrolyte solution was studied. In general the cathodic current density of adequate magnitudet applied by the external e.m.f. can fairly protect aluminum and its alloys from corrosion in various solutions except the alkali. In the case of salt solutions for example sodium chloride, aluminum can also be protected by cathodic current, provided that the current density is not too high. If the current density exceeds the limiting value, the cathodic corrosion does occur. The condition necessary to protect aluminum and its alloys from corrosion in various solutions can be summarized as follows:

Contact of aluminum and its alloys with baser metals such as zinc can also protect aluminum, for the actual measurement of the current through the circuit of these combined metals and alloys showed just the same amount as mentioned in the above table. The cathodic current of the Alclad duralumin core afforded by aluminum coating is also in the range of protective condition as shown in the table.

In conclusion, one must be careful that the aluminum and its alloys has both the upper and lower limits for the protecting current in the salt solution. The current density above the upper limit produces a bad effect. Contact with a metal which is too basic to aluminum causes corrosion of the latter. For example, the contact with magnesium accelerates the corrosion of aluminum and its alloys in sodium chloride solution. The coating materials of alclad plate must supply the sufficient current to protect the core alloy, but must not exceed the critical value.

Table 1

Electrolyte	NaCl 0.5N	NaCl 0.5N	NH_4Cl 1N	$ZnCl_2$ 1N	HCl 0.1N	HCl 0.5N	NaOH 0.005-0.1N
Alloy	For Al	For 24S	For Al	For Al	For Al	For Al	For Al
Protective current density (A/cm^2)	2 - 7	3 - 6	>8	>35	>450	>5000	....
Protective Potential referred to 1N Calomel Cell (v)	-0.9- -1.4	-0.65- -0.70	<-0.9	<-1.08	<-0.9	<-0.9	Impossible

The cathodic corrosion of aluminum and its alloys is not due to the reduction of oxide film by atomic hydrogen evolved at the cathode as in the case of stainless steel, but due to the cathodic production of caustic by electrolysis of salt solution by the current of so-called cathodic protection.—JSPS.

5.2.1, 3.6.9

Technical Practices in Cathodic Protection. *J. Am. Water Works Assoc.*, 43, 883-896 (1951) Nov.

Describes briefly the fundamentals of the application of cathodic protection and the mitigation of any electrolytic corrosion that may be caused by stray current from cathodic-protection systems. 62 references.—BLR.

5.4 Non-Metallic Coatings and Paints

5.4.2, 7.1, 3.5.9

Ceramic for Hot Spots. C. L. Foushee, Jr. *Aero Digest*, 63, 32+ (1951) Aug.

Work of Ryan Aeronautical Co. in application of ceramic coatings to exhaust manifolds of powerful new piston engines. Application procedures and test results.—BLR.

5.4.2, 3.5.9, 8.9.1

Recent Ceramic Coatings for High-Temperature Alloys. *Ind. Heating*, 18, No. 12, 2263-2264+ (1951).

A detailed account is given of the ceramic coatings developed by the U. S. National Bureau of Standards and intended for application to the exhaust systems of aircraft engines. The coatings are applied by spraying or dipping and then fired for a few minutes at 1850° F (1000° C.). The coatings give protection against scaling and intergranular corrosion. The most widely used coating (A417) is composed of a high-Ba, alkali-free frit (glass) with a 30% admixture of chromic oxide. The fired greenish colored layer can have controlled thicknesses between 0.001 and 0.002 in. The results of tests on Inconel parts coated with A-417 are reported.—MA.

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5.4.2, 4.2.3, 3.5.9, 8.9.1, 6.5

Ceramic and Special Alloys. W. G. Hubbell. Ryan Aeronautical Co. *Aeronaut. Eng. Rev.*, **10**, No. 11, 24-30 (1951) Nov. See also: Ceramic-Coated Exhaust-Systems. *Aircraft Prod.*, **13**, No. 157, 357-362 (1951) Nov.; *Iron Age*, **168**, No. 21, 81-85 (1951) Nov. 22. *Automotive Inds.*, **105** 48-50+ (1951) Nov. 1; *Metal Progress*, **60**, 87-91+ (1951) Dec.

Results of a series of tests conducted with ceramic coated exhaust system components by the Ryan Dev. Labs showed that the ceramic provided the protection necessary to extend the life of 19-9DL stainless steel at elevated temperatures encountered in aircraft service. No deterioration by oxidation, carbon absorption, or corrosion attack was evidenced in the components protected by the ceramic coatings for test periods running to 1,623 hours. A thermal shock resistance test showed that the ceramic coating, Bureau of Standards No. A-417, is not affected by thermal shock as encountered in exhaust system service at any temperature between —75° F. and 1,700° F. and that it will stand a surprising amount of mechanical impact without sustaining damage. Exhaust headers for testing were fabricated of the following materials: 19-9DL stainless steel, 17-14 copper-molybdenum, 310 mod. stainless steel, 310 with cobalt added, Inconel X, N-155 (Multimet) and Hastelloy C. Tests consisted of metallographic examinations, photomicrographs, spectrographic analyses, micro-hardness readings, and dial gage micrometer observations.—INCO.

5.4.2, 6.2.3, 3.5.9

High Temperature Coating for Steel. *Eng. and Boiler House Rev.*, **66**, 249-250 (1951) Aug.

A report recently issued by the Industrial Gas Development Committee of the Gas Council is related to a method of protecting mild steel against the effects of high temperature by a method, known as the "Stoneclad" process, and which involves coating mild steel parts with a refractory facing. In the report it is stated that unprotected mild steel is not suitable for long periods of use in an oxidizing atmosphere at temperatures above 500° C. It has hitherto been necessary to resort to the use of heat-resisting steel in cases where a material having the mechanical properties of mild steel had to be exposed continuously to temperatures much in excess of that figure. As the cost of heat-resisting steel is about twelve times that of mild steel and furthermore the fabrication of articles from heat-resisting steel is usually considerably more difficult than from mild steel the resulting article manufactured from heat-resisting steel is much more expensive. The new process consists in carrying, in a borosilicate matrix, a suspension of insoluble refractories and bonding it to the metal surface by fusion at about 800° C., The treatment may consist in a single homogeneous coat of approximately 0.004 inch thickness in applications where resistance to oxidation only is required, or it may comprise two coats, the upper one being porous, 0.020 inch to 0.060 inch thick and more refractory than the lower one. The properties of the coating depend upon the proportion of refractory to matrix, the particle size, the number of layers present and porosity of the upper face—it being always non-porous at the metal interface.—TIME.

5.4.2, 8.4.5

Enamels for Metals. J. H. Handwerk and T. N. McVay. U. S. Atomic Energy Commission Publ., Oct. 24, 1951 (ORO-47), 92 pp.

Vitreous enamels were required for shielding nuclear reactors and to provide both protection from oxidation and thermal insulation of iron plates at temperatures greater than 1100° C. Enamels with barium oxide content of 60% had a long firing range, matured from 1310° to 1420° C., and gave high-luster coatings, but were not resistant to strong acids although partially resistant to mild alkali solutions. Coatings containing 60% lead oxide matured at 760°-815° C., had a short firing range, and resembled those with 60% cadmium oxide. Various compositions for ground coat enamels with high barium or lead contents are suggested as suitable absorbers for γ-radiation. Enamels containing addition of boric anhydride of up to 47% of the melted weight of frit were not satisfactory as ground coats for sheet iron due to lack of adherence to the metal. Laminated plates with up to 12 metal sheets bonded together with enamel had a fair resistance to mechanical shock and could be fabricated into a wide variety of shapes whose physical properties were dependent on the type of enamel used. The enamels containing a high % of lead or barium were not suitable for making laminated plates owing to the marked difference in expansion coefficient of enamel and iron. Enamels containing lithium oxide had variable properties and were inferior to those in which sodium oxide was used as the alkali. Preliminary tests showed that iron could be protected from oxidation at high temperatures by an enamel coating and that the protection was improved by incorporating refractory materials such as carbides of boron or silicon into the enamel.—MA.

5.4.5

Epon Resins. T. R. Hopper. *Am. Ink Maker*, **29**, 61+ (1951) Oct.

Discusses a group of synthetic resins which are products of reaction between epichlorohydrin and polyhydroxy compounds. Their use in protective and decorative coatings is described.—BLR.

5.4.5

Rust-Protective Paints. H. Hesse. *Metalloberflache*, **3B**, 56 (1951); *Werkstoffe u. Korrosion*, **2**, No. 12, 476 (1951).

The danger of adding oil to a primer which is to form part of a balanced protective system is emphasized.—RPI.

5.4.5

Selection of Organic Coatings for Metal Products. A. G. Gray. *Products Finishing*, **15, No. 12**, 54-78 (1951) Sept.

An account of a lecture by M. A. Glaser on some important factors in the formulation of industrial finishes for metal products. The properties of many modern paint ingredients are described, and the ways in which they are put to use are illustrated by reference to the development of some special finishes. A table shows which vehicles are best for abrasion resistance, color retention, quick drying, etc. The article ends with a discussion on heat-resistant finishes.—ZDA.

5.4.5, 5.4.7

Paint, Surface Finish and Design. L. A. Jordon. *Chemistry and Industry*, **1951**, 981-987, Nov. 17.

Surveys the above. Causes of adhesion

failure of paint films applied by spray are discussed as well as other factors concerned with spraying.—BLR.

5.9 Surface Treatment

5.9.4, 6.4.2

Corrosion Tests of Duralumin Anodically Treated in Chromic Acid Solutions. H. C. DAVIS. Protection and Electrodeposition of Metals. Selected Government Research Rep. Vol. 3. London. Obtainable from His Majesty's Stationery Office. p. 165-170 (1951).

Specimens of Duralumin to B.S. Specification 3L3 were anodically treated in electrolytes containing 3,5, and 10% chromate at various stages of exhaustion, using the normal Bengough voltage cycle. Some specimens were also treated in 10% chromate at constant voltages of 30 and 40 V. The specimens were exposed to sea-water spray for a period of 18 months. The corrosion tests do not confirm what might be inferred from the fact that the film produced in the 10% chromate bath is thicker than that produced in weaker baths (cf. Willstrop, *ibid*, p. 56), namely that such a film would have better protective value. In fact, the film produced in the 10% solution is less protective than those produced in the 3 and 5% solution. Little or no advantage over normal Bengough treatment is obtained by operating 10% chromate solution either at a constant voltage of 30V. or with the normal Bengough voltage cycle. Films produced in 5% chromate solution are less protective against corrosion by sea-

water than standard Bengough films. 3% chromate solution can be used satisfactorily on Duralumin until the 0.5 normal sodium carbonate titration value falls to 1.70 c.c. though such baths may in practice be scrapped before this value is reached for other reasons, such as contamination with foreign matter.—MA.

5.11 Design—Influence on Corrosion

5.11, 6.4.2, 8.1.2

Aluminum in Structural Engineering. W. C. DEVEREUX. *Engineer* (England), 192, No. 4984, 150-151 (1951) Aug. 3.

The most important difference between design technique for light alloy and that for steel is the effect of the lower modulus of elasticity, which property affects deflection and the design of compression members. In the past these standards of deflection were based on steel structural practice. The new standards allow much more reasonable deflections in aluminum structures.

Apart from the material cost, the most expensive part of structural engineering is joining the various members together. "Pop" reveting is fairly successful for light structures, but has serious limitations for heavier work. Lack of flexibility has forced the use of steel bolts for most of the site joints in large structures. This is unsatisfactory as they have to be made to close tolerances and specially protected against rusting.

In welding large structures, the mass of the member being welded has an important bearing on the behavior and properties of the weld. The atmospheric corrosion resistance of aluminum is superior to that of most other structural materials. The corrosion rate of aluminum decreases with time and is independent of the thickness of the specimen.

The corrosion of aluminum and alloys can be accelerated if wet or moist corrosion products are allowed to accumulate on the surface. This would indicate that in designing aluminum structures, care must be taken to ensure that static water should not be allowed to remain continuously in contact with aluminum and its alloys. Construction has been limited to the use of one major alloy—BS.STA 7/AW.10 B—an alloy of the aluminum magnesium silicide type, which can be readily extruded to the thinnest practical sections. It has a yield strength comparable with mild structural steel.—ALL.

6. MATERIALS OF CONSTRUCTION

6.1 General

6.1, 1.6

Materials Handbook. GEORGE S. BRADY. 913 pages. 1951. McGraw-Hill Book Co., 33 W. 42nd St., New York 18, New York.

Presents general information, with the most commonly used comparative figures on materials in their group classifications in order to give a general picture. Patented and trade-named materials are described to give a more specific understanding of commercial applications. The relative position and the length of description of proprietary materials are for purpose of illustration and bear no relation to the relative merits of the products of any one producer.—BLR.

6.1, 1.6, 2.5, 5.11

Engineering Materials Manual. Edited by T. C. DuMond. 11½ x 8½ in. pp. (iii) + 386, with many illustrations and tables. 1951. New York. Reinhold Publishing Corp. ($4.00); London: Chapman and Hall, Ltd. (36s.)

This volume describes in the minimum of words, with the aid of many diagrams, tables, and illustrations, most of the materials now being used in engineering works. The 28 sections into which it is divided each present an overall picture of a single material or group of materials. They are essays on engineering materials which have been written, by 14 separately named authors, for the series of "Materials and Methods Manuals" which have been published in *Materials and Methods* during recent years. They were produced primarily for those practical engineers who may be potential users of the materials, and the limitation of space, in view of the width of field covered has been met by a praiseworthy economy in words.

There are, to begin with, sections on the standard engineering steels, stainless steels, high-strength low-alloy steels, tool steels and free-cutting steels, and grey-iron castings. Wrought and cast aluminum and magnesium alloys, nickel alloys, engineering bronzes, beryllium-copper, and bearing metals are then described in sections which constitute the non-ferrous metals group of subjects. The latter half of the book deals with cemented carbides, ceramics, rubber, plastics, hard-facing materials, finishes for metals, and adhesives. The sections dealing with subjects of which the reviewer has a more intimate knowledge proved on reading to be well-balanced presentations from the American point of view. They do not cover European-made material specifications, but there are a few brief references to European developments.

Although not intended primarily for metallurgists, there are few members of the Institute who would not find this volume a useful addition to their library, and it will be especially valuable to those connected with production engineering. Its value as a reference book will be greater in the United States than in other countries, but it provides a mass of authoritative information which would be difficult to find had the authors not gathered it conveniently in this manner. The book will be a timely aid to the many designers and technical assistants who must day by day consider the choice of materials for essential components, when the use of any scarce material must be justified, and almost all are scarce.—MA.

6.2 Ferrous Metals and Alloys

6.2.5, 2.3.7, 3.5.9

Various Methods for Perfection of Alloys Having Good Mechanical Properties at High Temperatures. (In French). A. Guessier. *Metaux: Corrosion-Industries,* **26**, 310-317 (1951) July-Aug.

Describes procedures and apparatus used for stainless steels, in addition to classical methods, which make possible extensive testing with a minimum expenditure of time and effort. Advantages of these auxiliary methods are indicated; data are tabulated and charted. 14 references.—BLR.

6.2.5, 3.7.3, 4.3.2

Report on Chemical Corrosion of Welded Samples of Type 347 Stainless Steel. H. C. ELLINGHAUSEN. Naval Engineering Experiment Station, Annapolis, Md. Apr. 10, 1951. 14 pp.

Results of chemical corrosion tests are presented for specimens of Type 347 stainless steel containing a weld deposited with 19-9 niobium electrodes. Specimens were exposed in boiling acidulated copper sulfate solution, and in boiling 65% nitric acid after sensitizing at 800°, 1100°, and 1300°F temperatures for periods of 2, 6, and 24 hours prior to testing. Exposure for 72 hours in boiling copper sulfate solution resulted in no serious deterioration as determined by a bend test. Microscopic examination revealed no signs of intergranular attack. Following the second 48 hour period in boiling nitric acid some samples revealed severe knife-line attack immediately adjacent to the weld. The attack was most severe for samples that had been sensitized for six and twenty-four hours at 1100°F, and for two and six hours at 1300°F. Results are reported for the tests in nitric acid consisting of three periods of 48 hours each. Control tests were made on Type 347 base metal. (Author.)—NSA.

6.2.5, 3.7.3, 4.3.2

Chemical Corrosion Tests of Welded Samples of Type 347 Stainless Steel (Supplementary report). H. C. ELLINGHAUSEN, Naval Engineering Experiment Station, Md. May 15, 1951. 3 pp.

Welded samples of Type 347 stainless steel sensitized at 1100°F for two, six, and twenty-four hours sustained knife-line attack when they were exposed in boiling 65% nitric acid (Huey Test). The degree of attack increased with sensitizing time from 192 to 240 hours. Similar samples sensitized at 1300°F for two and six hours also suffered knife-line attack. However, the degree of attack decreased with increase in time. A specimen held for 24 hr. at 1300°F and samples sensitized at 800°F for two, six, and 24 hours showed no evidence of knife-line attack. None of the base-metal control samples were susceptible to localized attack.—NSA.

NOTE: For original report see card No. 4545.

6.2.5, 4.3.1, 4.4.1

Notebook on Corrosion Resistance. Carpenter Steel Co., Alloy Tube Div., Union, N. J. 1951. 15 p. Gratis.

Data are presented on the types, specifications, corrosion resistance, and recommended uses of Carpenter stainless tubing. A table of corrosion resistance showing the resistance of a number of stainless steels to common and troublesome chemicals is included.

6.2.5, 2.3.4, 3.7.4

Investigations on Stainless Steel. A. FERRI. *Metallurgia Italiana*, **43**, No. 10, 432-434 (1951) Oct.

A series of intercrystalline corrosion cycles have been carried out by the author on three types of suitably sensitized 18-8 austenitic steels in order to allow the sensitivity characteristics of Strauss' tests and of tests in boiling nitric acid to be fully understood. On the basis of obtained results, a higher sensitivity can be attributed to Strauss' test—aside from the already known inhibiting action of titanium and molybdenum and of the influence of heat-treatment. The spreading shown by the

corrosion values (as obtained by measurement of electrical resistivity) are related, in a preliminary way to a number of factors that are involved in the reactions leading to intercrystalline corrosion, as, i.e., the grain size, the amount of carbide precipitations and the surface conditions of test pieces.—TDD.

6.2.5, 4.7, 6.5

High Chromium Steels Resist Attack by Liquid Bismuth Alloys. JOHN L. EVERHART AND EDGAR L. VAN NUIS. *Materials & Methods*, **34**, 112-114 (1951) Oct.

Discusses the properties of some of the bismuth alloys. Their use in heat-transfer applications depends on suitable material to contain them. Corrosion tests on a number of constructional materials are presented. High chromium alloys are more resistant than nickel-chromium materials. Data are tabulated. Illustrations.—BLR.

6.2.5, 6.2.2, 1.6, 3.7.3

Stainless Steels in Industry. Vol. 1. Stainless Iron and Steel. Ed. 3. J. H. G. MONYPENNY. Book, 523 p. Chapman and Hall, Ltd., 37 Essex St., London W.C. 2, England. 45s. (1951).

Varieties of stainless steels in commercial use, with compositions, characteristic features, and properties of particular importance to the engineer and metalworker. Methods recommended for fabrication of the steels into useful equipment, and their response under varying conditions of corrosive attack and temperature. Factors affecting selection of suitable forms of stainless steel for specific industries.—MR.

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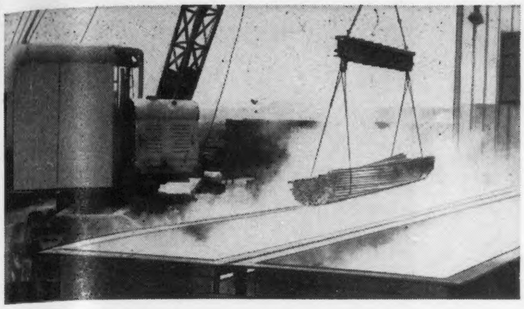
6.2.5, 6.3.15, 4.7, 6.5

Final Report; Problem No. 539. J. L. EVERHART AND E. L. VAN NUIS. American Smelting and Refining Co. June 15, 1951. 28 pp.

Unstressed static and dynamic tests have been run on a number of standard stainless steels, proprietary steels, titanium and several titanium alloys, vanadium, and zirconium to determine their resistance to attack by various liquid low-melting Bi-base alloys of indium, lead, tin, and thallium. The effect of temperature on the viscosities of the bismuth-base alloys has been investigated.—NSA.



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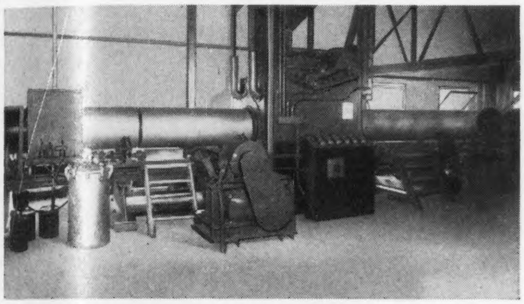

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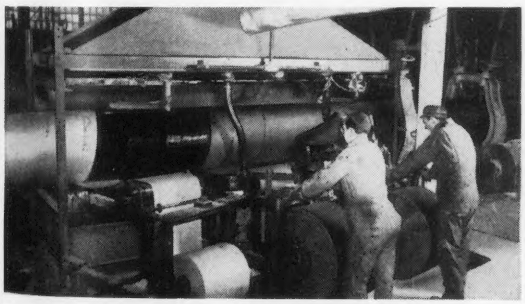

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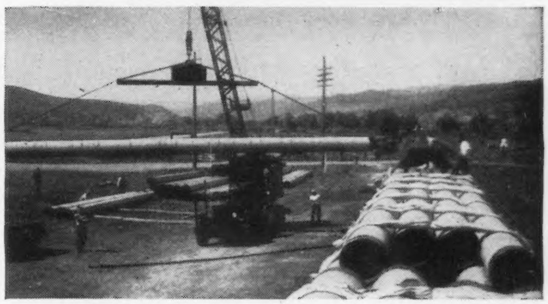

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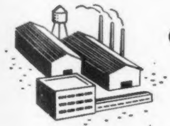
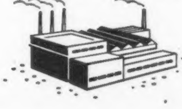


GIRARD, OHIO
in the Youngstown Switching Zone



LORAIN, OHIO

HAMMOND, IND.
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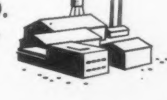

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